1. Approved Consent Agenda items:
   a. Approve July 30, 2013 minutes
   b. Markets and Operations Policy Committee Recommendations
      i. ORWG: CRR 005, 006, and 007
      ii. MWG: MPRR 069, 101, 131, 132, 135, 138, 139, 140, 141, 149
      iii. SPCWG: Criteria 7.0
      v. Staff: Novation from GMO & KCPL to Transource
         1. Iatan-Nashoa
         2. NE City to Sibley
      vi. PCWG: Bowers – Howard
   c. Human Resources Committee Recommendation
      vii. Pension Plan
2. Approved the Corporate Governance Committee’s recommendation that the Board of Directors approve the appointment of Venita McCellon-Allen (AEP) to serve on the Strategic Planning Committee, effective December 1, 2013.
3. Approved the Corporate Governance Committee’s recommendations that the Board of Directors approve the Scopes for the Board committees as presented.
4. Approved the Corporate Governance Committee’s recommendations to recover and allocate the costs of the FERC Penalty under Schedule 1-A.
5. Approved the Corporate Governance Committee’s recommendation that the Board of Directors approve the change in the formula for financial obligations upon withdrawal. Filing of this change is pending concurrence from SPP’s lenders, which is currently being sought.
6. Approved the Corporate Governance Committee’s recommendation for approval of the Bylaws revision reflecting that for purposes of seating representatives on the CGC, Affiliates have one vote.
7. Approved the Staff’s recommendation that the Board of Directors approve the revisions to the Bylaws and Membership Agreement to meet SPP’s compliance filing obligation as directed by FERC clarifying regional transmission costs upon withdrawal.
8. Approved the Finance Committee’s recommendation that the Board of Directors approve the 2014 SPP operating and capital budgets as submitted.
9. Approved the Finance Committee’s recommendation that the Board of Directors establish an assessment rate and tariff administrative fee (schedule 1-A) of 38.1¢/MWh beginning January 1, 2014.
10. Approved the Finance Committee’s recommendation that the Board of Directors approve the issuance of up to $70 million in debt securities to fund SPP’s capital expenditure program through 2016. Said approval was subject to the following conditions:

1. Authorize issuance of up to $70 million in secured and unsecured notes with maturities of up to 12 years;
2. Authorize appropriate regulatory filings for the issuance of up to $70 million in secured and unsecured notes with maturities of up to 12 years to be issued within 24 months of receiving regulatory approval;
3. Authorize SPP Finance Committee to oversee negotiation, final approval of terms and conditions, and authorization to execute up to $70 million in secured and unsecured notes with maturities of up to 12 years;
4. Authorize the SPP President and CFO to jointly execute notes and agreements for the issuance of up to $70 million in secured and unsecured notes with maturities of up to 12 years, upon final authorization of the SPP Finance Committee.

11. Approved the Markets and Operations Policy Committee’s recommendation that the Board of Directors approve Tariff Revision Requests TRRs 104 and 110 with the three-tiered bid deposit:

<table>
<thead>
<tr>
<th>Bid Deposit</th>
<th>Small Proposal (&lt; $10M)</th>
<th>Medium Proposal (&lt; $10M to $100M)</th>
<th>Large Proposal (&gt; $100M)</th>
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<td>Bid Deposit</td>
<td>$10,000</td>
<td>$25,000</td>
<td>$50,000</td>
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12. Approved the Markets and Operations Policy Committee’s recommendation that the Board of Directors approve its request regarding MPRR 130.

13. Approved the Markets and Operations Policy Committee’s recommendation that the Board of Directors approve its request regarding MPRR 145.

14. Approved the Markets and Operations Policy Committee’s recommendation that the Board of Directors approve the recommended scope for ITP 10 and direct staff to develop with stakeholders an analytical approach that will yield useful information to be included in the ITP-10 report that provides a measure of the ability of the recommended portfolio to accommodate Future 3 assumptions and needs.
Southwest Power Pool

BOARD OF DIRECTORS/MEMBERS COMMITTEE MEETING

SPP Corporate Office, Little Rock, AR

October 29, 2013

**Agenda Item 1 - Administrative Items**

SPP Chair Mr. Jim Eckelberger called the meeting to order at 8:45 a.m. The following Board of Directors/Members Committee members were in attendance or represented by proxy:

- Mr. Larry Altenbaumer, director
- Ms. Phyllis Bernard, director
- Mr. Ricky Bittle, Arkansas Electric Cooperative
- Mr. Julian Brix, director
- Mr. Nick Brown, director
- Mr. Phil Crissup, Oklahoma Gas and Electric
- Mr. Mike Deggendorf, Kansas City Power and Light
- Mr. Jon Hansen, proxy for Mr. Mo Doghman, Omaha Public Power District
- Mr. Jim Eckelberger, director
- Mr. Kelly Harrison, Westar Energy
- Mr. Rob Janssen, Dogwood Energy
- Mr. Tom Kent, Nebraska Public Power District
- Mr. Jeff Knottke, City Utilities of Springfield
- Mr. Brett Kruse, Calpine Energy Services
- Mr. Josh Martin, director
- Mr. Dave Osburn, Oklahoma Municipal Power Authority
- Mr. Roy Klusmeyer, proxy for Mr. Gary Roulet, Western Farmers Electric Cooperative
- Mr. Harry Skilton, director
- Mr. Kevin Smith, Tenaska
- Mr. Stuart Solomon, American Electric Power
- Mr. Noman Williams, Sunflower Electric Power Corporation
- Mr. Mike Wise, Golden Spread Electric Cooperative

There were 123 persons in attendance either in person or via phone representing 34 members (Attendance List - Attachment 1). Mr. Nick Brown reported proxies and a quorum was declared (Proxies - Attachment 2).

**Agenda Item 2 – Board Reports**

**Regional State Committee Report**

Ms. Dana Murphy (Oklahoma Corporation Commission) presented the Regional State Committee (RSC) report. Ms. Murphy stated that the group held an educational session prior to the regular meeting, which covered the Southwest Power Pool (SPP) structure and help in navigating the SPP website. The RSC found this information very helpful and appreciated being able to offer suggestions for the future website. She thanked Mr. Paul Suskie and Mr. Sam Loudenslager for providing forms on action items to be presented in the meeting and for agreeing to provide the meeting materials earlier to allow more time for review.

Ms. Murphy announced the RSC newly elected officers as: President, Donna Nelson; Vice President, Dana Murphy; and Secretary/Treasurer, Patrick Lyons.

Ms. Murphy reported the RSC approved the 2014 Budget of $353,300, which has increased due to increased travel expenses.
The RSC acted on three items: approved the Order 1000 recommendation on Cost Allocation related to Third Party Impacts; approved Markets and Operations Policy Committee’s recommendation on MPRR 138; and accepted the Regional Allocation Review Task Force Report.

Ms. Murphy said that cost will continue to be a high priority for the RSC and noted that the Administrative Fee increase caught the group’s attention. Ms. Murphy stated that due to the RSC turnover, President Wright had introduced the idea of the RSC naming an Executive Director for the purpose of continuity.

Mr. Jim Eckelberger acknowledged Mr. Tom Wright for his great service as President of the RSC over the past year.

Federal Energy Regulatory Commission Report
Mr. Patrick Clarey provided an update on recent FERC activities. At the Open Meeting this month, the ISO/RTOs presented their updates regarding efforts at natural gas and electric coordination. These reports focused on continuing efforts in the coordination and understanding of the interdependency of natural gas and electric markets within the ISO/RTOs. Mr. Clarey noted that SPP participated in this and especially thanked Don Shipley and Joe Ghormley for their efforts.

The Commission also directed staff to conduct a workshop to explore certain pricing issues involving the filing of rate schedules for reactive power. Additionally, the Commission ordered that rate schedules for reactive power be filed even if no rates are charged for those services. Staff is directed to explore the mechanics of generators filing such rate schedules.

On September 25, the Commission held a technical conference to consider how current centralized capacity market rules and structures in the regions served by ISO New England Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), and PJM Interconnection, L.L.C. (PJM) are supporting the procurement and retention of resources necessary to meet future reliability and operational needs.

Finally, FERC announced the schedule for the Open Meetings in 2014. The meetings will continue to be held on the third Thursday of every month except for August. The open meeting dates for the 2014 calendar year are as follows:

January 16  May 15  October 16
February 20  June 19  November 20
March 20  July 17  December 18
April 17  September 18

Regional Entity Trustees Report
Mr. John Meyer presented the Regional Entity Trustee report (RE Report – Attachment 3). The report included updates on:

- Transition from Critical Infrastructure Protection (CIP) Version 3 to Version 5
- Major short-term Reliability Assurance Initiatives (RAI)
- Facility Ratings Alert Update
- NERC 3Q 2012 Vegetation Management Report
- Regional Standards Update
- SPP RE Region Misoperation Counts
- Most Violated Standards
- Outreach

Oversight Committee Report
Mr. Josh Martin presented the Oversight Committee Report. The Committee met in Chicago in September.

- The Committee heard quarterly reports from Internal Audit, Compliance, and Market Monitoring staff.
o Internal Audit continues its regular audits, as well as its oversight role in the Integrated Marketplace initiative. The group continues to focus on higher-risk areas, and particularly those that intersect with the Integrated Marketplace initiative.

o The primary focus for the Compliance group has been preparations for and conduct of SPP’s CIP and 693 audits, which were conducted during the quarter. The group is now preparing for the BA certification visit in November. Compliance Forums were held in August and October; the next one will be held in February in Dallas. These continue to be well-attended, and in coordination with the Regional Entity to ensure meaningful agendas.

o The Market Monitoring Unit staff remains engaged in the Integrated Marketplace initiative, developing the various new metrics that will be necessary to monitor the new markets.

• At the Committee’s request, the Staff developed a summary report of the various audit, oversight, and monitoring activities that occur throughout the organization. This report was very informative. Staff will further enhance the report, providing an updated version at the December Board meeting, which is focused on organizational effectiveness.

• The Committee approved engaging Boston Pacific in 2014 to prepare a Looking Forward Report as they have in previous years. This contract will be finalized at the December meeting.

The Oversight Committee’s next scheduled meeting is December 9 in Little Rock.

**Agenda Item 3 – Consent Agenda**

Mr. Eckelberger presented the following Consent Agenda items for approval (Consent Agenda – Attachment 4):

a. Approve July 30, 2013 minutes

b. Markets and Operations Policy Committee Recommendations
   i. ORWG: CRR 005, 006, and 007
   ii. MWG: MPRR 069, 101, 131, 132, 135, 138, 139, 140, 141, 149
   iii. SPCWG: Criteria 7.0
   v. Staff: Novation from GMO & KCPL to Transource
      1. Iatan-Nashua
      2. NE City to Sibley
   vi. PCWG: Bowers – Howard

e. Human Resources Committee Recommendation
   i. Pension Plan

Mr. Eckelberger asked for requests to remove any items from the Consent Agenda or a motion to approve. Mr. Noman Williams recommended a change of language in Action Item five of the July 30, 2013 minutes to reflect that MOPC recommended two futures and the Board approved three futures. Following discussion regarding MPRR 101 and TRR 107, no items were pulled from the Consent Agenda. Mr. Harry Skilton moved to approve the Consent Agenda items with the minutes to be revised as noted; Mr. Larry Altenbaumer seconded the motion. The Members Committee voted in unanimous approval. The Board voted; the motion passed.

**Agenda Item 4 – Corporate Governance Report**

Mr. Nick Brown provided the Corporate Governance Report (CGC Report – Attachment 5). Mr. Brown reported that there will be a vacancy on the Strategic Planning Committee effective December 1, 2013. In accordance with the SPP Bylaws, the CGC recommends a candidate to the Board of Directors for consideration and appointment. The CGC recommendation is: The Corporate Governance Committee recommends the appointment of Venita McCellon-Allen (AEP) to serve on the Strategic Planning Committee, effective December 1, 2013.
Mr. Nick Brown moved to approve; Mr. Julian Brix seconded. The Members Committee voted in unanimous approval. The Board voted; the motion passed.

Mr. Brown stated that at the Corporate Governance Committee’s recommendation in regards to Board Committee scopes, the Board of Directors approved revising the SPP Bylaws to remove the detailed activities for each, capturing those in each committee’s respective Scope document. That filing has been approved at FERC. The Committee presented the following Scopes for approval: Corporate Governance Committee, Finance Committee, Human Resources Committee, Markets and Operations Policy Committee, Oversight Committee and Strategic Planning Committee. **Mr. Brown moved for approval of the Scopes for the Board committees as presented; Mr. Josh Martin seconded. The Members Committee voted in unanimous approval. The Board voted; the motion passed.**

Mr. Brown reported that on July 10, 2013, FERC issued an Order approving a Stipulation and Consent Agreement approving an agreement between SPP and FERC to settle an investigation conducted by FERC into possible violations of Reliability Standards associated with SPP’s reliability coordination of a portion of the Bulk Power System. SPP must file to recover this penalty. **Mr. Brown moved to approve the Corporate Governance Committee’s recommendation to recover and allocate the costs of the FERC penalty under Schedule 1-A. The Members Committee voted in unanimous approval. The Board voted; the motion passed.**

Mr. Brown presented the following Bylaws revisions requests:

The formula for calculating withdrawal fees included a factor for “Net Energy for Load (NEL) in SPP” used for no other purpose than calculating withdrawal obligations. The CGC determined the more appropriate calculation is for “The load served by transmission facilities under the SPP Open Access Transmission Tariff.” Staff has determined that Schedule 12 Load is the appropriate factor to use since it is currently reported to SPP for other purposes and somewhat verifiable. **Mr. Brown moved to approve the Corporate Governance Committee’s recommendation to approve the change in the formula for financial obligations upon withdrawal. Filing of this change is pending concurrence from SPP’s lenders, which is currently being sought. Mr. Julian Brix seconded. The Members Committee voted in unanimous approval. The Board voted; the motion passed.**

Mr. Brown stated that SPP’s Bylaws are very clear that for purposes of elections, Affiliate entities can cast only one vote, while for other purposes (ex: MOPC), each member company has one vote. For purposes of seating CGC representatives, the Bylaws state only that the members will select a representative, without regard to Affiliates. Following discussion, the Committee recommends: **The Corporate Governance Committee recommends approval of the Bylaws revision reflecting that for purposes of seating representatives on the CGC, Affiliates have one vote. Mr. Brown moved to approve the recommendation; Ms. Phyllis Bernard seconded. The Members Committee voted in unanimous approval. The Board voted; the motion passed.**

Mr. Brown reported that FERC accepted SPP’s revisions to its governing documents to address the treatment of regional transmission costs upon withdrawal (to be negotiated on a case-by-case basis) from the organization but required a compliance filing clarifying that the new provisions apply only to transmission owners. **Mr. Brown moved to approve the following: Staff recommends approval of the revisions to the Bylaws and Membership Agreement to meet SPP’s compliance filing obligation as directed by FERC. Mr. Larry Altenbaumer seconded. The Members Committee voted in unanimous approval. The Board voted; the motion passed.**

**Agenda Item 5 – Finance Committee Report**

Mr. Harry Skilton presented the Finance Committee Report (FC Report – Attachment 6). Mr. Skilton presented the 2014 budget prepared with a “zero-based” approach and presented in a new format to provide better information. The biggest cost drivers are the scheduled retirement of debt obtained to fund the development of the Integrated Marketplace and other capital expenditure projects, and increased support and maintenance for the Integrated Marketplace systems.
SPP’s management proposed a 2014 budget to include expenditures as follows:

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<th>Category</th>
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<td>Operating Expense (incl. dep. &amp; am.)</td>
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<tr>
<td>Debt Repayment</td>
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<td>FERC Assessments</td>
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<tr>
<td>Capital Expenditures</td>
<td>$37.1</td>
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Mr. Skilton moved to approve the Finance Committee recommendation to the SPP Board of Directors to approve the 2014 SPP operating and capital budgets as submitted.

Mr. Skilton provided information regarding the 2014 administrative and assessment fee rate. Following discussion, Mr. Skilton moved to approve the Finance Committee’s recommendation that the SPP Board of Directors establish an assessment rate and tariff administrative fee (schedule 1-A) of 38.1¢/MWh beginning on January 1, 2014. Mr. Larry Altenbaumer seconded. The Members Committee voted in favor with Mr. Mike Deggendorf in opposition. The Board voted; the motion passed.

Mr. Skilton provided background regarding the 2014 term financing. The Finance Committee recommends the following: Approve the recommendation of the SPP Finance Committee to issue up to $70 million in debt securities to fund SPP’s capital expenditure program through 2016. Said approval was subject to the following conditions:

1. Authorize issuance of up to $70 million in secured and unsecured notes with maturities of up to 12 years;
2. Authorize appropriate regulatory filings for the issuance of up to $70 million in secured and unsecured notes with maturities of up to 12 years to be issued within 24 months of receiving regulatory approval;
3. Authorize SPP Finance Committee to oversee negotiation, final approval of terms and conditions, and authorization to execute up to $70 million in secured and unsecured notes with maturities of up to 12 years;
4. Authorize the SPP President and CFO to jointly execute notes and agreements for the issuance of up to $70 million in secured and unsecured notes with maturities of up to 12 years, upon final authorization of the SPP Finance Committee.

Mr. Skilton moved to approve; Mr. Larry Altenbaumer seconded. The Members Committee voted in unanimous approval. The Board voted; the motion passed.

Agenda Item 6– Markets and Operations Policy Committee Report

Mr. Rob Janssen provided the Markets and Operations Policy Committee report (MOPC Report – Attachment 7). Mr. Janssen gave an overview of the following action items and recommendations for approval:

RTWG – TRR 104, 110

Mr. Janssen stated the MOPC recommends the approval of TRR 104, revisions to Attachment Y and addition of Addendum 5 to Attachment O to address Order 1000 regional compliance, and approval of TRR 110, revisions to Attachment Y and O to address Order 1000 regional compliance. The MOPC recommendation asks the Board of Directors to approve the Tariff Revision Requests TRRs 104 and 110. MOPC’s motion included a change for the deposit in TRR 110 from $50,000 to $10,000. In regards to TRR 110, SPP Staff offered an alternative three-tiered bid deposit (Order 1000 Bid Deposit – Attachment 8). Following discussion, the recommendation is: The Board of Directors approve Tariff Revision Requests TRRs 104 and 110 with the three-tiered bid deposit:
Mr. Nick Brown moved to approve; Mr. Harry Skilton seconded. The Members Committee voted in favor with Mr. Tom Kent in abstention. The Board voted; the motion passed.

MWG – MPRR 130, 145
Mr. Richard Ross stated that MPRR 130 provides more detail to the must offer design and penalty calculation and rules filed in February 2013. The MOPC recommends that the Board of Directors approve the MPRR 130. Mr. Nick Brown moved to approve; Ms. Phyllis Bernard seconded. The Members Committee voted in favor with Mr. Kelly Harrison and Mr. Brett Kruse in abstention. The Board voted; the motion passed.

Mr. Ross then provided information for MPRR 145 regarding Head-room and Floor-room Capacity Requirements. The MOPC recommends that the Board of Directors approve the MPRR 145. Mr. Julian Brix moved to approve; Larry Altenbaumer seconded. The Members Committee voted in favor with Mr. Rob Janssen and Mr. Ricky Bittle in abstention. The Board voted; the motion passed.

ESWG – 2015 ITP 10 Scope
Mr. Alan Myers presented information for the 2015 ITP 10 Scope. The MOPC reviewed three futures: Business as Usual, Decreased Base Load Capacity, and Increased Input Prices. Following much discussion the MOPC recommends: The Board of Directors approve the 2015 ITP10 Resource Plan as modified: Delete Future 3 and Staff move forward with Futures 1 and 2; Delete the Final Portfolio Consolidation Section.

Mr. Richard Ross then presented an alternative from American Electric Power (AEP) (2015 ITP 10 Scope Alternative – Attachment 9). After much discussion, Mr. Nick Brown provided the following motion: Approve MOPC recommended scope and direct staff to develop with stakeholders an analytical approach that will yield useful information to be included in the ITP-10 report that provides a measure of the ability of the recommended portfolio to accommodate Future 3 assumptions and needs.

Ms. Julian Brix seconded the motion. The Members Committee voted in unanimous approval. The Board voted; the motion passed.

Agenda Item 7– Integrated Marketplace Report
Mr. Bruce Rew provided the Integrated Market report (IM Report – Attachment 10). Mr. Rew gave an overview of TCR market trials, market trials, parallel operations and deployment testing, cutover and go-live planning, readiness and outreach, and post go-live activities.

Agenda Item 8 – Future Meetings
Mr. Eckelberger reminded the group of the SPP Board of Directors teleconference meeting on November 4 to approve tariff language for the compliance filing. The next meeting will be in Little Rock on December 10 and will focus on organizational effectiveness (Future Meetings – Attachment 11).

Adjournment
With no further business, Mr. Eckelberger thanked everyone for participating and adjourned the meeting to Executive Session at 2:40 p.m.

Stacy Duckett, Corporate Secretary
Executive Session:

The Board and Members Committee heard an initial report from Phyllis Bernard, Chair of the Human Resources Committee, regarding salary market adjustments for SPP employees.
Southwest Power Pool

BOARD OF DIRECTORS/MEMBERS COMMITTEE MEETING
AND ANNUAL MEETING OF MEMBERS
October 29, 2013
SPP Offices, Little Rock, AR

• AGENDA •
8:00 a.m. – 3:00 p.m. CDT

Annual Meeting of Members
1. Call to Order and Administrative Items.................................................................Mr. Jim Eckelberger
2. Elections of Directors, Members Committee Representatives, and RE Trustee ..........Mr. Nick Brown
3. President’s Report ........................................................................................................Mr. Nick Brown

Adjourn for Board of Directors/Members Committee Meeting

Board of Directors/Members Committee Meeting
1. Call to Order and Administrative Items................................................................. Mr. Jim Eckelberger
2. Board Reports
   a. Regional State Committee Report................................................................. Commissioner Tom Wright
   b. Federal Energy Regulatory Commission Report........................................... Mr. Patrick Clarey
   c. Regional Entity Trustees Report....................................................................... Mr. John Meyer
   d. Oversight Committee Report............................................................................. Mr. Josh Martin
3. Consent Agenda ....................................................................................................... Mr. Jim Eckelberger
   a. Approve July 30, 2013 minutes
   b. Markets and Operations Policy Committee Recommendations
      i. ORWG: CRR 005, 006, and 007
      ii. MWG: MPRR 069, 101, 131, 132, 135, 138, 139, 140, 141, 149
      iii. SPCWG: Criteria 7.0
      v. Staff: Novation from GMO & KCPL to Transource
         1. Ilatan-Nashoa
         2. NE City to Sibley
   c. Human Resources Committee Recommendation
      i. Pension Plan
4. Corporate Governance Committee Report...............................................................Mr. Nick Brown
5. Finance Committee Report...................................................................................... Mr. Harry Skilton
6. Markets and Operations Policy Committee Report ....................................................... Mr. Rob Janssen
   a. RTWG: TRR 104, 110
   b. MWG: MPRR 130, 145
   c. ESWG: 2015 ITP10 Scope
7. Integrated Marketplace Update ................................................................................... Mr. Bruce Rew
8. Future Meetings ......................................................................................................... Mr. Jim Eckelberger
   BOD – November 4............................................... Teleconference
   BOD – December 10...................................................... Little Rock
   2014
   RET/RSC/BOD - January 27-28 ................................. Austin
   RET/RSC/BOD - April 28-29 ................................... Oklahoma City
   BOD - June 9-10 .......................................................... Little Rock
   RET/RSC/BOD - July 28-29 ....................................... Omaha
   RET/RSC/BOD - October 27-28 .............................. Little Rock
   BOD - December 10...................................................... Little Rock

Executive Session
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<td>Bryce Freeman</td>
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<td>Ray Benjamin</td>
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<td>Steve Still</td>
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<td>KCP&amp;L</td>
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<tr>
<td>Mike Bernard</td>
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<tr>
<td>Jeff Kotteke</td>
<td>SPRM</td>
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## ATTENDANCE LIST

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<thead>
<tr>
<th>Name</th>
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<tbody>
<tr>
<td>Stuart Solomon</td>
<td>AE? (PSO/SWENCO)</td>
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<tr>
<td>KEVIN SMITH</td>
<td>TENASKA</td>
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<tr>
<td>Roy Klusmeyer</td>
<td>WFEC</td>
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<tr>
<td>John Meyer</td>
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<tr>
<td>Barbara Sugg</td>
<td>SPP</td>
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<tr>
<td>Chuck Marshall</td>
<td>ITC GREAT PLAINS</td>
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<tr>
<td>Alan Myers</td>
<td>&quot; &quot; &quot; &quot;</td>
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<tr>
<td>KRISTINE SCHMIDT</td>
<td>ITC GREAT PLAINS</td>
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<td>BRETT LEOPOLD</td>
<td>ITC GREAT PLAINS</td>
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<td>Dave Christiano</td>
<td>SPP RE Trustee</td>
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<td>GERRY BURROWS</td>
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<td>CARL A. MONROE</td>
<td>SPP</td>
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<tr>
<td>Tom Burke</td>
<td>GSEC</td>
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<td>Michelle Fishbach</td>
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<td>Bill Harrelson</td>
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<td>Cheryl Robertson</td>
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<td>Sara Smith</td>
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<td>Stacy Duckett</td>
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<td>Matt Birnette</td>
<td>Wright &amp; Tabarin</td>
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<td>John Krupinski</td>
<td>NE Power Review Board</td>
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## ATTENDANCE LIST

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<tr>
<td>Adam McKinnies</td>
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<td>Walt Cecil</td>
<td>HoPSC Staff</td>
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<tr>
<td>Jim Jacoby</td>
<td>AEP</td>
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<tr>
<td>Rata Sundararatnam</td>
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<td>Todd Fridley</td>
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<td>Bruce Rew</td>
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<td>Michael Posselle</td>
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<td>Paul Siskie</td>
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<td>Lanny Nickel</td>
<td>SPP</td>
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<td>Steve Drew</td>
<td>O6+E</td>
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<td>Kimber Shop</td>
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<td>Terri Gallup</td>
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<td>Antonio Smythe</td>
<td>DEAN SOURCE</td>
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<td>Malinda Lee</td>
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<td>Robert Satito</td>
<td>Customized Energy Solutions</td>
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<td>Jay Casey</td>
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<td>Walt Shumate</td>
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<tr>
<td>Brian Georich</td>
<td>NEXTERA</td>
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<td>Bill Reid</td>
<td>Climate &amp; Energy Project</td>
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<td>Name</td>
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<tr>
<td>Scott Heffdrick</td>
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<td>Darrel Bullington</td>
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<td>Todd Hillard</td>
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<td>Paul Jeff</td>
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<td>Pat Mosier</td>
<td>ARK. PSC</td>
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<td>Cindy Ireland</td>
<td>ARK. PSC</td>
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<tr>
<td>Tom DeBened</td>
<td>KANSAS CORP. COM.</td>
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<td>Katherine Prevost</td>
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<td>C. Richard Ron</td>
<td>AEPCSC</td>
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<td>Sam Loudenslager</td>
<td>SPP STAFF</td>
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<td>Chuck Cook</td>
<td>Regions Bank</td>
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<td>Kevin Brown</td>
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<td>Mike Waters</td>
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<tr>
<td>Wendell Deosth</td>
<td>Alstom Grid</td>
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<td>Russ McGee</td>
<td>Alstom Grid</td>
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</table>
Southwest Power Pool

BOARD OF DIRECTORS/MEMBERS COMMITTEE MEETING
AND Annual Meeting of Members

October 29, 2013

ATTENDANCE LIST

<table>
<thead>
<tr>
<th>Name</th>
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<tbody>
<tr>
<td>Martha Reine</td>
<td>Ratepayer</td>
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<tr>
<td>David Linton</td>
<td>ITC Great Plains</td>
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<tr>
<td>Patrick Claypool</td>
<td>FERC</td>
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<tr>
<td>Jim Foley</td>
<td>OPPD</td>
</tr>
<tr>
<td>Keith Tyson</td>
<td>East Texas</td>
</tr>
<tr>
<td>Bernie Lui</td>
<td>Xcel</td>
</tr>
</tbody>
</table>
Jon Hansen will act as a proxy at the Board meeting for Mo Doghman with his voting rights this also covers the Annual Meeting of Members.

Thanks,

Christi Labs
Executive Administrative Assistant
Omaha Public Power District
444 South 16th Street Mall, Omaha, NE 68102
402-636-3212
calabs@oppd.com
October 3, 2013

TO WHOM IT MAY CONCERN:

I, Gary R. Roulet, Chief Executive Officer of Western Farmers Electric Cooperative (WFEC), hereby authorize Roy Klusmeyer to represent WFEC and vote on WFEC’s behalf at the Southwest Power Pool Meetings scheduled for October 28 and 29, 2013, in Little Rock, Arkansas.

Sincerely,

[Signature]
Gary R. Roulet
Chief Executive Officer

GRR:jp
SPP RE Update to Board of Directors

October 29, 2013

John Meyer
Chairman, SPP RE Trustees

Major Topics

1. Transition from CIP Version 3 to Version 5
   - NERC published transition guidance 4/11/13 and revised guidance 7/17/13
   - Waiver from CIP V3 compliance being sought for seven entities in NERC’s CIP V5 transition study, including Westar
   - Expect FERC action by end of year

2. Major short-term Reliability Assurance Initiatives (RAI)
   - Common Auditor Handbook 1Q 2014
   - Streamlined Find, Fix, Track (FFT) process 1Q 2014
   - Pilot programs for Self-Reporting 2Q 2014
Facility Ratings Alert Update

- Nearing the end of 4-year program to review ratings and remediate discrepancies
- Discrepancies found:
  - High/Medium Priorities
    - SPP RE ~ 2,300
    - NERC ~ 26,000
  - Low Priority
    - SPP RE ~ 650 (to date)
    - NERC (no report yet)
- Remediation required within one year of discovery

Vegetation Management Update

- NERC 3Q 2013 Vegetation Management Report
  - No reportable contacts in SPP RE footprint
  - 2nd consecutive quarter with no reportable contacts
Regional Standards Update

- On 8/5/13, SPP RE Trustees approved recall of regional UFLS standard from FERC
- NERC posted revised *SPP RE Regional Standard Process Development Manual* for public comment through 8/9/13
  - NERC does not ballot Manual revisions
- NERC will consider both items at November Board of Trustees meeting

SPP RE Misoperation Report as of 2Q 2013

*Relay Operational Performance - Success Rate*

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Success Rate</th>
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<tbody>
<tr>
<td>Q1-11</td>
<td>85.6%</td>
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<tr>
<td>Q2-11</td>
<td>90.1%</td>
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<tr>
<td>Q3-11</td>
<td>90.1%</td>
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<tr>
<td>Q4-11</td>
<td>88.9%</td>
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<tr>
<td>Q1-12</td>
<td>82.9%</td>
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<tr>
<td>Q2-12</td>
<td>92.2%</td>
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<td>Q3-12</td>
<td>92.6%</td>
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<td>Q4-12</td>
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<tr>
<td>Q1-13</td>
<td>85.9%</td>
</tr>
<tr>
<td>Q2-13</td>
<td>85.7%</td>
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<tr>
<td></td>
<td>87.6%</td>
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Most Violated Standards

Based on rolling 12 months through 9/30/13 [Represents ~ 80% of total violations]

<table>
<thead>
<tr>
<th>SPP RE Rank</th>
<th>NERC 12 Month Rank*</th>
<th>Standard</th>
<th>Description</th>
<th>Number Violations</th>
<th>Risk Factor</th>
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<tr>
<td>1</td>
<td>1</td>
<td>CIP-007</td>
<td>Systems Security Management (HI)</td>
<td>37</td>
<td>Med./Lower</td>
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<tr>
<td>2</td>
<td>3</td>
<td>CIP-005</td>
<td>Electronic Security Perimeters (HI)</td>
<td>26</td>
<td>Med./Lower</td>
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<tr>
<td>3</td>
<td>2</td>
<td>CIP-006</td>
<td>Physical Security-Critical Assets</td>
<td>26</td>
<td>Med./Lower</td>
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<td>4</td>
<td>4</td>
<td>PRC-005</td>
<td>Protection System Maintenance (HI)</td>
<td>14</td>
<td>High/Lower</td>
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<td>5</td>
<td>10</td>
<td>FAC-009</td>
<td>Facility Ratings</td>
<td>11</td>
<td>Med./Lower</td>
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<tr>
<td>6</td>
<td>7</td>
<td>CIP-003</td>
<td>Security Management Controls</td>
<td>10</td>
<td>Med./Lower</td>
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<td>7</td>
<td>6</td>
<td>CIP-004</td>
<td>Personnel &amp; Training</td>
<td>7</td>
<td>Med./Lower</td>
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<td>8</td>
<td>8</td>
<td>VAR-002</td>
<td>Network Voltage Schedules</td>
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<td>Med./Lower</td>
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<td>9</td>
<td>**</td>
<td>PRC-008</td>
<td>UFLS Relay Maintenance</td>
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<td>10</td>
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<td>CIP-002</td>
<td>Critical Cyber Asset Identification (HI)</td>
<td>3</td>
<td>High/Med.</td>
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* NERC Report Q2 2013
** Not in NERC Rolling 12 month Top Ten
(HI) Standards in RED include requirements designated as High Impact Violations

Outreach

- 7 new staff videos posted to video training webpage
  - CIP Standards Violation Analysis, 2008-2012
  - CIP-005 R2, Electronic Access Controls
  - How to Read & Understand Standards
  - Comprehensive Mitigation
  - How to Use EFT Server
  - Internal Controls (CIP)
  - CIP-003 R5, Access Control

- Webinars
  - Nov. 21, 10:00 CST - 2014 Implementation Plan/2013 Self Assessment Webinar

- Save the Date for 2014 Workshops/Forums!
  - Feb. 25-27, Dallas
  - June 3-5, Little Rock
  - Sept. 30-Oct. 2, Oklahoma City
Outreach

• 163 stakeholder attendees in-person/webinar at Fall Workshop

  ![Workshop Overall](chart)

• Have held break-out discussions at last 2 workshops to give staff/attendees opportunity to talk in small groups
  – Have been very popular; we will continue including
Southwest Power Pool

BOARD OF DIRECTORS/MEMBERS COMMITTEE MEETING

Marriott City Center, Denver, Colorado

July 30, 2013

- Summary of Action Items -

1. Approved Consent Agenda items:
   a. Approve April 30 and July 1, 2013 minutes
   b. Markets and Operations Policy Committee
      i. RTWG: TRR093, TRR095, TRR096
      ii. MWG: PRR 244
          MPRR 117, 118, 120, 121, 122, 123, 124, 125, 128
      iii. Staff: Transmission Service Waiver (KMEA)
          Hays Plant-South Hays 115kV NTC Reevaluation and Possible Modification
   c. Finance Committee
      i. Auditor Engagement

2. Approved the Finance Committee’s recommendation that the Board of Directors approve to increase the Schedule 1-A admin fee cap to 39¢/MWh and authorize SPP staff to make the appropriate filings with FERC for approval.

3. Approved the Markets and Operations Policy Committee’s recommendations that the Board of Directors approve its request regarding TRR091’s Backlog Clearing Process as approved by MOPC in the white paper in April 2013.

4. Approved the Markets and Operations Policy Committee’s recommendations that the Board of Directors approve the 2013 ITP20 report as documentation of completion of the 20-Year Assessment of the ITP planning process specified in SPP OATT Attachment O Section III, and endorse the 2013 ITP20 plan as outlined in the 2013 ITP20 report.

5. Approved the Markets and Operations Policy Committee’s 2015 ITP10 recommendation that the Board of Directors approve the development of a resource plan for three Futures: Business as Usual, Decreased Base Load Capacity, and Increased Input Prices and reevaluate at the October meeting.

6. Approved the Markets and Operations Policy Committee’s recommendation that the Board of Directors approve two key assumptions for 2015 ITP10 study: 1) the inclusion of 50/50 HPILS loads and Board approved HPILS NTCs; 2) directed MOPC to treat HVDC facilities as a sensitivity case and inclusion in the study would depend upon further examination.

7. Approved the Markets and Operations Policy Committee’s recommendation that the Board of Directors approve MPRR 133 giving Staff, working with the RTWG Chair, latitude to update language to allow Staff the flexibility to decline nominating ARRs. The implementation of the appropriate software for the distribution of the net of the “carve-out” would trigger a resettlement from the default distribution through RNU back to the start of the Market.
8. Approved the Markets and Operations Policy Committee’s recommendation that the Board of Directors provide an advisory vote to the SPP RE that PRC-006-SPP-1 be withdrawn from FERC consideration as a Regional Standard due to the fact that NERC PRC-024-1 has been approved by NERC and is waiting on FERC approval.
Southwest Power Pool
BOARD OF DIRECTORS/MEMBERS COMMITTEE MEETING
Marriott City Center, Denver, Colorado
July 30, 2013

Agenda Item 1 - Administrative Items
SPP Chair Mr. Jim Eckelberger called the meeting to order at 8:00 a.m. The following Board of Directors/Members Committee members were in attendance or represented by proxy:

- Mr. Larry Altenbaumer, director
- Ms. Phyllis Bernard, director
- Mr. Ricky Bittle, Arkansas Electric Cooperative
- Mr. Julian Brix, director
- Mr. Nick Brown, director
- Mr. Phil Crissup, Oklahoma Gas and Electric
- Mr. Scott Heidbrink, proxy for Mr. Mike Deggendorf, Kansas City Power and Light
- Mr. Mo Doghman, Omaha Public Power District
- Mr. Jim Eckelberger, director
- Mr. Kelly Harrison, Westar Energy
- Ms. Cindy Holman, Oklahoma Municipal Power Authority
- Mr. Rob Janssen, Dogwood Energy
- Mr. Tom Kent, Nebraska Public Power District
- Mr. Jeff Knottek, City Utilities of Springfield
- Mr. Brett Kruse, Calpine Energy Services
- Mr. Gary Roulet, Western Farmers Electric Cooperative
- Mr. Harry Skilton, director
- Mr. Kevin Smith, Tenaska
- Mr. Stuart Solomon, American Electric Power
- Mr. Noman Williams, Sunflower Electric Power Corporation
- Mr. Mike Wise, Golden Spread Electric Cooperative

There were 117 persons in attendance either in person or via phone representing 34 members (Attendance List - Attachment 1). Mr. Nick Brown reported proxies and a quorum was declared (Proxies - Attachment 2).

Agenda Item 2 – Board Reports
President’s Report
Mr. Nick Brown provided the President’s Report (President’s Report – Attachment 3). Mr. Brown stated that on July 18, 2013 FERC issued an order regarding SPP’s Order 1000 Compliance filing. Of the several items that may require a request for rehearing, it was disappointing that the request for Right of First Refusal (ROFR) was rejected. In an earlier order, the Commission had approved the ROFR. There were two dissenting votes, which everyone was encouraged to read. SPP will continue to analyze the order.

In April, SPP agreed to accept a settlement from FERC for an event that took place in December 2007, neither admitting nor denying fault. The July 10, 2013 Order required SPP to pay a $50,000 fine with half to NERC and half to the Treasury.

SPP marked one year on the new campus on July 16. SPP was recently notified that the facility meets LEEDS Gold status. The building has had a positive impact on the budget in that we no longer pay $1 million per year in rent for office space and no longer need to rent meeting space.
Mr. Brown announced that Southwest Power Pool had been selected as one of twelve companies that make up the inaugural class for Arkansas Business’ Best Places to Work in Arkansas. Arkansas Business partnered with the internationally renowned Best Companies Group and the Arkansas Society of Human Resource Management to bring the Best Places to Work program to the state.

Mr. Brown reported that SPP is on budget showing 3% below on revenues and 3% below on expenses. SPP will not fill eight positions budgeted for 2013.

Mr. Brown referred to the SPP Metrics included in the background material and asked Mr. Carl Monroe to provide commentary and answer any questions.

Mr. Brown announced this to be Ms Cindy Holman’s last meeting with SPP as she will retire on July 31, 2013, from Oklahoma Municipal Power Authority and thus from the SPP committees she serves. He presented Ms. Holman with a resolution and thanked her for her great service to SPP.

Regional Entity Trustee Report
Mr. John Meyers presented the Regional Entity Trustee report (RE Report – Attachment 4). The report included updates on:

- New Definition of Bulk Electric System
- Facility Ratings Alert
- Transition from CIP Version 3 to Version 5
- NERC “Blue Ribbon Panel” to review standards
- Most Violated Standards
- 1Q SPP RE Region Misoperation Report
- NERC Reports
- Outreach

Regional State Committee Report
Mr. Tom Wright (Kansas Corporation Commission) presented the Regional State Committee (RSC) report. Mr. Wright stated that it was the nature of the RSC to have a varying degree of knowledge due to turnover in members and terms. That being the case, the group took the opportunity to meet in Colorado Springs for an educational retreat between the NARUC and SPP meetings. Mr. Wright thanked and complimented staff on well presented material addressing the process improvement, Integrated Marketplace, Market Monitoring, and transmission planning.

Mr. Wright said the RSC met July 29. The group heard updates on Order 1000 Regional and Interregional, planning and processes, Long Term Financial Transmission Rights, Regional Cost Allocation Review, the Rate Impact Task Force, Integrated Marketplace and Integrated Transmission Planning. The RSC approved the Cost Allocation Working Group’s definition of “mandates” and “goals” for the treatment of renewable resources in planning.

Oversight Committee Report
Mr. Larry Altenbaumer presented the Oversight Committee Report for Mr. Josh Martin, Committee Chair. The Committee met in Little Rock in June and heard quarterly reports from Internal Audit, Compliance, and Market Monitoring staff.

- Internal Audit continues its regular audits, as well as its oversight role in the Integrated Marketplace initiative. Plans are to continue the focus on higher-risk areas, and particularly those that intersect with the Integrated Marketplace initiative.

- The primary focus of Compliance has been the launch of the Regional Compliance Working Group, and preparations for SPP’s first comprehensive CIP audit, which was conducted during the last week of June/first of July. A Compliance Forum was held May 23; the next one will be held August 7-8 in Little Rock. These continue to be well-attended.
• The Market Monitoring Unit staff remains engaged in the Integrated Marketplace initiative, developing the various new metrics that will be necessary to monitor the new markets. Last year, SPP was awarded $1 million as part of FERC’s settlement with Constellation for market violations. The funds were to be used to support or enhance market monitoring efforts. Earlier this month, SPP received approval for its proposal for use of these funds and will proceed accordingly.

• The committee also heard briefings for each department’s 2014 budget, and updates to strategic plans.

The Oversight Committee’s next scheduled meeting is September 26 in Chicago.

Human Resources Committee Report
Ms. Phyllis Bernard stated that there was no formal Human Resources Committee report. The group will hold its annual retreat September 10 - 11 in Little Rock at the SPP Corporate Campus. Ms. Bernard also reiterated Mr. Brown’s remark that Southwest Power Pool was chosen in the inaugural class of the twelve best places to work in Arkansas.

Corporate Governance Committee Report
Mr. Nick Brown presented the Corporate Governance Committee report. Mr. Brown announced that nominations are open for several committee vacancies including:

• Members Committee, a mid-term Municipals opening (election in October)
• TO vacancy on the SPC effective December 1 (appointed by CGC with Board approval)
• IOU vacancy on CGC effective December 1 (IOU members will select)
• Municipals vacancy on CGC effective August 1 (Muni members will select)

He asked that nominations be submitted to either himself or Ms. Stacy Duckett.

The Committee submitted a filing regarding withdrawal obligations for transmission expansion costs. At the next meeting on August 29, the group will review services versus fees to ensure equity, review scopes of Board committees and discuss cost allocation for an entity joining SPP.

Agenda Item 3 – Consent Agenda
Mr. Eckelberger presented the following Consent Agenda items for approval (Consent Agenda – Attachment 5):

a. Approve April 30 and July 1, 2013 minutes
b. Markets and Operations Policy Committee
   ii. RTWG: TRR093, TRR095, TRR096
   iii. MWG: PRR 244
       MPRR 117, 118, 120, 121, 122, 123, 124, 125, 128
   iv. Staff: Transmission Service Waiver (KMEA)
       Hays Plant-South Hays 115kV NTC Reevaluation and Possible Modification
c. Finance Committee
   v. Auditor Engagement

Mr. Eckelberger asked for requests to remove any items from the Consent Agenda or a motion to approve. Mr. Julian Brix moved to approve the Consent Agenda items; Mr. Harry Skilton seconded the motion. The Members Committee voted in unanimous approval. The Board voted; the motion passed.
Agenda Item 4 – Integrated Marketplace Report

Mr. Bruce Rew provided the Integrated Market report (IM Report – Attachment 6). Mr. Rew gave an overview of the first seven weeks of market trials and discussed preparation for parallel operations and final steps for Go-Live and post-Go-Live. Concerns were raised regarding the number of entities engaged, JOAs and seams issues, and post market enhancement for combined cycle. Following discussion, it was suggested to set deadlines for participants’ engagement and testing, be more diligent regarding seams and develop a plan for enhancements following market Go-Live.

Agenda Item 5 – Strategic Planning Committee Report

Mr. Ricky Bittle provided a Strategic Planning Committee report. The Committee reformed the SPCTF on Order 1000 to address the recent order (SPCTF Order 1000 – Attachment 7). He reviewed the Order timeline, Order findings and outlined SPCTF recommendations. The group recommends that SPP seek rehearing and clarification (due on August 18) on the following issues:

Rehearing
- Mobile-Sierra
- Byway funding
- Removal of exemption on existing rights-of-way
- Inclusion of Aggregate Study projects
- State Right of First Refusal (ROFRs)

Clarification
Approved Aggregate Study NTCs prior to January 2015

It was the consensus that SPCTF should proceed with the recommendations as presented.

The SPCTF plans to schedule meetings to develop policy guidance for the compliance filing, begin dialogue with the RSC, CAWG on cost allocation and state ROFRs, and understand implications for the ITP10 that will yield NTCs in January 2015.

Agenda Item 6 – Finance Committee Report

Mr. Harry Skilton presented the Finance Committee Report (FC Report – Attachment 8). Mr. Skilton addressed activities of the Committee regarding: Pension Fund Management, Auditor Engagements, Schedule 1-A Administrative Fee Cap, CFTC Exemption and Aviation Strategy. The Schedule 1-A administrative fee cap was set when the tariff was implemented. As SPP adds services, SPP’s costs have risen but also have resulted in significant benefits to the SPP region. The administrative fee continues to grow but SPP’s forecast indicates costs/MWh will level off and slightly decline in the foreseeable future, assuming no new services are added. The Committee wants to raise the current 35¢/MWh cap to cover forecasted costs and recommends the following:

The Finance Committee recommends the SPP Board of Directors approve an increase the Schedule 1-A admin fee cap to 39¢/MWh and authorize SPP staff to make the appropriate filings with FERC for approval.

Mr. Harry Skilton moved for approval; Mr. Larry Altenbaumer seconded. The Members Committee voted in unanimous approval. The Board voted; the motion passed.

Agenda Item 7 – Markets and Operations Policy Committee Report

Mr. Rob Janssen provided the Markets and Operations Policy Committee report (MOPC Report – Attachment 9). Mr. Janssen gave an overview of the following action items and recommendations for approval:
RTWG – TRR091

This is the first stage of Aggregate Study improvements, the Backlog Queue Clearing Process, as approved in white papers by the MOPC and the Board of Directors in April 2013 (TRR091 Recommendation – Attachment 10). MOPC approved tariff language and requested that the Board of Directors approve TRR091. Mr. Julian Brix moved to approve; Ms. Phyllis Bernard seconded. The Members Committee voted in unanimous approval. The Board voted; the motion passed.

Following approval, direction was requested on the timing of a FERC filing. Due to the fact that the Backlog Clearing Process can only be implemented on the Active Study between iterations, it was suggested to set an aggressive timeline with an effective date prior to October 15 in order to implement in the next gap between iterations. This would require a filing in the next two weeks. It was the consensus to meet this timeline and avoid delaying until the next round of studies.

ESWG – ITP20 and ITP10

Mr. Alan Myer provided background on the 2013 ITP20 Report (ITP20 Recommendation – Attachment 11) and asked that the Board of Directors approve the report as documentation of completion of the 20-Year Assessment of the ITP planning process specified in SPP OATT Attachment O Section III. MOPC further recommends the Board endorse the 2013 ITP20 plan as outlined in the 2013 ITP20 report. Mr. Larry Altenbaumer moved to approve the 2013 ITP20 report and plan as requested; Mr. Harry Skilton seconded. The Members Committee voted in favor with Mr. Jeff Knottek voting against. The Board voted; the motion passed.

Mr. Myers then provided background on the 2015 ITP10 (ITP10 Recommendation – Attachment 12), Strategic Planning scenarios and drivers, and proposed futures. He noted that the ESWG had recommended the adoption of three Futures (Business as Usual, Decreased Base Load Capacity, and Increased Input Prices). He reported that MOPC had a lengthy dialogue about the third Future and after debate voted to only approve two Futures (Business As Usual and Decreased Baseload Capacity). Following much discussion, the recommendation was revised to develop a resource plan for three Futures: Business as Usual, Decreased Base Load Capacity, and Increased Input Prices and reevaluate at the October meeting. Mr. Larry Altenbaumer moved to approve the revised recommendation; Ms. Phyllis Bernard seconded. The Members Committee voted in favor with Mr. Mike Wise and Mr. Jeff Knottek in abstention. The Board voted; the motion passed.

Mr. Janssen reviewed and requested approval of two 2015 ITP10 key assumptions:

Approve the inclusion of 50/50 HPILS loads and Board approved HPILS NTCs in the 2015 ITP10 Study.

Approve inclusion of new HVDC facilities in the 2015 ITP10 study if they have executed Transmission – Transmission Interconnection Agreement (both ends) and flows across the facilities being based on firm transmission service.

Following discussion, the motion regarding HVDC facilities was revised to direct MOPC to view this as a sensitivity case and inclusion in the study would depend upon further examination.

Mr. Nick Brown moved for approval as revised; Mr. Julian Brix seconded. The Members Committee voted in favor with Mr. Mike Wise and Mr. Jeff Knottek in abstention. The Board voted; the motion passed.

MWG – MPRR133

Mr. Richard Ross provided background regarding MPRR133, the GFA Carve Out (MPRR133 Recommendation – Attachment 13). SPP received three directives from FERC in the October 18, 2012 Marketplace Order:

- Begin settlement negotiations with protesters who are parties to GFAs
• File an informational filing 90 days after issuance of the order
• After informational filing, SPP may commence a stakeholder process to finalize a Carve Out proposal for the GFAs that:
  o Have not been integrated into the Integrated Marketplace and which merit a Carve Out

MWG approved a GFA Carve Out design on June 19, 2013 and recommended the following:

**Approve MPRR133 giving Staff, working with the RTWG Chair, latitude to update language to allow Staff the flexibility to decline nominating ARRs. The implementation of the appropriate software for the distribution of the net of the “carve-out” would trigger a resettlement from the default distribution through RNU back to the start of the Market.**

Following considerable discussion, Mr. Julian Brix moved for approval; Mr. Larry Altenbaumer seconded. The Members Committee voted in favor with Mr. Mo Doghman, Mr. Tom Kent and Mr. Rob Janssen against, and Mr. Kevin Smith in abstention. The Board voted; the motion passed.

**SPCWG - UFLS Standard Removal**

Mr. Janssen provided background regarding the removal of the UFLS Regional Standard (UFLS Standard Recommendation – Attachment 14). The MOPC recommendation is:

**The Board of Directors provide an advisory vote to the SPP RE that PRC-006-SPP-1 be withdrawn from FERC consideration as a Regional Standard due to the fact that NERC PRC-024-1 has been approved by NERC and is waiting on FERC approval.**

Mr. Harry Skilton moved for approval; Mr. Larry Altenbaumer seconded. The Members Committee voted in unanimous approval. The Board voted; the motion passed.

Due to time constraints, Mr. Janssen ended his report. Additional MOPC informational items can be found in the attached report.

**Agenda Item 8 – Future Meetings**

Mr. Eckelberger reminded the group the next SPP Board of Directors meeting will include the Annual Meeting of Members and be held on October 29, 2013 in Little Rock (Future Meetings – Attachment 15).

**Adjournment**

With no further business, Mr. Eckelberger thanked everyone for participating and adjourned the meeting at 3:28 p.m.

Stacy Duckett, Corporate Secretary
Organizational Roster
The following members represent the Operating Reliability Working Group:

American Electric Power          Mr. Dennis Sauriol
CLECO                      Mr. Danny McDaniel
Southwestern Public Service     Mr. Kyle McMenamin
Westar Energy                  Mr. Allen Klassen
Independence Power & Light      Mr. Paul Lampe
Nebraska Public Power District  Mr. Ron Gunderson
Omaha Public Power District     Mr. Todd Gosnell
Kansas City Power & Light       Mr. Jim Useldinger
Lincoln Electric System         Mr. Steve Haun
Sunflower Electric Cooperative  Mr. Allan George
City Utilities of Springfield   Mr. John Stephens
Southwestern Power Administration Mr. Michael Wech
Oklahoma Gas & Electric         Mr. Greg Mcauley
ITC Great Plains                Mr. Darrel Yohnk

The following stakeholders participated in group discussions:

American Electric Power          Mr. Dennis Sauriol
Southwestern Public Service      Mr. Kyle McMenamin
Westar Energy                   Mr. Allen Klassen
Independence Power & Light       Mr. Paul Lampe
Nebraska Public Power District   Mr. Ron Gunderson
Omaha Public Power District      Mr. Todd Gosnell
Kansas City Power & Light        Mr. Jim Useldinger
Sunflower Electric Cooperative   Mr. Allan George
City Utilities of Springfield    Mr. John Stephens
Southwestern Power Administration Mr. Michael Wech
Oklahoma Gas & Electric          Mr. Greg Mcauley

Background
Criteria 6.4.5 requires submission of a report to SPP within 2 business days following the issuance of an Other Extreme Condition (OEC) event. That written report has historically been provided to the Manager, Reliability Coordination. The proposed change clarifies a specific email address to submit the reports to, rather than simply providing the title of the individual who shall receive the report.

Analysis
In a meeting on August 15, 2013, the ORWG evaluated and approved the attached Criteria Revision Request #005 with a vote of 11 in favor, none opposed, no abstentions.

Recommendation
The MOPC recommends that the BOD approve the attached revision to Criteria 6 as noted in CRR005

APPROVAL: MOPC October 15-16, 2013
Approved Unanimously
## Criteria Revision Request

<table>
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### Section No.: 6.4.5

**Title:** Other Extreme Conditions Events

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<tr>
<td>Correction/Clean-Up</td>
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### Revision Description

Change the contact method for submission of EEA and OEC reports from Manager Reliability Coordination to a specific, generic email group.

### Reason for Revision

Removes the need for future revisions as SPP organization structure may change.

### Tariff Implications or Changes

- Yes – Section No.: *(Include a summary of impact and/or specific changes)*
- No

### Protocol Implications or Changes

- Yes - Section No.: *(Include a summary of impact and/or specific changes)*
- No

### Date

07/26/2012

### Sponsor

<table>
<thead>
<tr>
<th>Name</th>
<th>Terry Oxandale</th>
</tr>
</thead>
<tbody>
<tr>
<td>E-mail Address</td>
<td><a href="mailto:toxandale@spp.org">toxandale@spp.org</a></td>
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<tr>
<td>Company</td>
<td>Southwest Power Pool</td>
</tr>
<tr>
<td>Phone Number</td>
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<td>-------------------</td>
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</tr>
<tr>
<td>Date</td>
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**6.4.5 Other Extreme Conditions Events**

Other Extreme Conditions (OEC) Events may be requested by any Balancing Authority member of the SPP Reserve Sharing Group. OECs may be implemented for any of the following reasons, but shall be implemented when the requesting Balancing Authority has used all or a portion of its reserve obligation due to the event:

1. Loss of a Capacity Import Schedule
2. Loss of Reserves
3. Initial or additional assistance is required and no other mechanism is available within the confines of the SPP computer communication system.

Any member not having their Minimum Contingency Reserve Daily Requirement shall enter an Other Extreme Conditions for the amount of the deficiency. A NERC Energy Emergency Alert (EEA) may or may not be required. If the Balancing Authority determines an EEA must be issued, the Balancing Authority shall notify the Reliability Coordinator. If the OEC is requested along with an EEA, the Balancing Authority shall be prepared to demonstrate the emergency condition by taking the steps required by the EEA.

The SPP Reserve Sharing Group member submitting an Other Extreme Conditions event shall submit a written report to the Manager, Reliability Coordination OECEEAREports@spp.org within 2 business days of the event. The written report will describe the operating conditions that precipitated the event. Other Extreme Conditions shall be investigated as required by the SPP Operating Reliability Working Group to ensure compliance with SPP Criteria and NERC Reliability Standards.

**Proposed Criteria Language Revision**

None

**Proposed Tariff Language Revision**

None

**Proposed Protocol Language Revision**

None
Organizational Roster
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Oklahoma Gas & Electric         Mr. Greg Mcauley

Background
Criteria 6.4.2 requires submission of a Reserve Sharing event upon loss of generation rated at 50 MW or greater as well as other partial losses of capacity or an Other Extreme Condition event. The change proposed is to relax the “must enter” requirement to only events greater than 200 MW or those resulting in the contingent BA not possessing its normal reserve requirement. Of course, an RSS event may be entered for any type and magnitude of event as the contingent BA wishes. There are other miscellaneous clean up items proposed as well.

Analysis
In a meeting on September 11, 2013, the ORWG evaluated and approved the attached Criteria Revision Request #006 with a vote of 12 in favor, none opposed, no abstentions.

Recommendation
The MOPC recommends that the BOD approve the attached revision to Criteria 6 as noted in CRR006.
### Criteria Revision Request

<table>
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<th>Adjust Operating Reserve Contingency Event must enter requirement</th>
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<td>Section No.: 6.4.2</td>
<td>Title: Contingency Operation</td>
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<td>☐ Yes – If yes, estimated cost: TBD</td>
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<tr>
<td>Type of Revision</td>
<td>☐ Correction/Clean-Up</td>
<td>☐ Clarification</td>
<td>☒ Policy Change</td>
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<tr>
<td>Revision Description</td>
<td>Adjust the “must enter” requirement for Operating Reserve Contingency Events</td>
<td></td>
<td></td>
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<tr>
<td>Reason for Revision</td>
<td>Historically resource contingencies of a defined type or size have been required to be entered in the RSS system. There were several reasons for this including notifying the RSG of the contingency, use of operating reserves to recover it, and withdrawing/utilizing contingency reserves from the RSG during recovery.</td>
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<tr>
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<td>As the SPP BA is consolidated and the RSG membership changes, the need for a “must enter” requirement of small contingencies is reduced or eliminated. The CBA will be carrying the bulk of the CR for the RSG and the flexibility to choose to recover from small, unreportable (DCS) events without utilizing or taking away CR from the RSG is desired. The intent being that the RSG is there when necessary, but is not required to be utilized for EVERY event of a particular size or type. The individual BA Area operators participating in the RSG have the flexibility to decide when to call upon the RSG at their discretion, however still keeping a requirement to enter events of 200 MW or greater.</td>
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<td>☐ Yes - Section No.: <em>(Include a summary of impact and/or specific changes)</em></td>
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<td>Date</td>
<td>8/15/2013</td>
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6.4.2 Contingency Operation

These procedures shall be implemented immediately following the occurrence of an Operating Reserve Contingency of any type and magnitude, but are required to be implemented for Operating Reserve Contingencies as specified below.

- A complete or partial loss of 200 MW magnitude or greater of a resource, a generator rated at a resource of 50-200 MW magnitude or greater, or
- A partial loss of generating capacity of 75 MW or more, or
- A partial loss of generating output of 50 MW or more or
- A loss of a capacity purchase of 50 MW or more, or
- A loss of Operating Capacity resulting in the BA possessing less than its Minimum Daily Reserve Requirement, or,
- Any “Other Extreme Conditions” event.

These procedures may be implemented immediately following the occurrence of an Operating Reserve Contingency of any type and magnitude, as system conditions warrant, by the Contingency Area. These procedures are to be implemented in a non-discriminatory manner.

a. Immediately following an Operating Reserve Contingency, the Contingency Area shall report the occurrence via the SPP computer communication system Reserve Sharing System. This report shall contain a description of the contingency; the net MW lost due to the contingency and any MW amount of Contingency Reserve being carried on the contingency unit. For those generating units whose station auxiliaries do not decrease to essentially zero or increase after a unit trip, gross MWs lost shall be used instead of net MWs lost. The operating owner of jointly owned generating units shall be responsible for reporting outages and the MW amount lost by each owner.

b. Within the constraints described in this Criteria, allocation magnitudes shall be determined and notices distributed to the members of the Reserve Sharing Group.

c. The maximum amount assigned to any Balancing Authority for any single Operating Reserve Contingency shall not exceed its Spinning Reserve requirement unless the contingency reserve requirement exceeds the available Spinning Reserve of the SPP Reserve Sharing Group. The additional responsibility shall be allocated to other members of the SPP Reserve Sharing Group until the total Spinning Reserves are exhausted. Any remaining responsibility shall be allocated to the SPP Reserve Sharing Group by a similar procedure as the initial allocation out of the total
Supplemental Reserve. The Operating Reliability Working Group may adjust for any single member or for all members the maximum amount allocated.

d.c. The Assistance Schedule becomes part of each Assisting Area's scheduled net interchange and shall therefore be reflected in its ACE. The schedule shall be implemented at a zero time ramp rate immediately following allocation notification. If obvious and significant errors exist in assistance schedules, the Contingency Area system operator shall dictate appropriate corrective action during the Contingency Period, and notify the SPP.

e.d. Assisting Areas shall immediately acknowledge receipt of the allocation notice via the SPP computer communication system Reserve Sharing System. If a Contingency Area fails to receive acknowledgment from an Assisting Area, the SPP Reliability Coordinator shall notify the Assisting Area of the assistance schedule.

f.e. The Contingency Area(s) and Assisting Areas shall provide the requested assistance within the requirements established in the Disturbance Recovery Criterion of the NERC Reliability Standards.

g. After the implementation of the allocation, the Contingency Area and Assisting Areas shall report to the SPP, when their ACE returned to zero or it’s pre-contingency level whichever is achieved first.

h.f. The Contingency Reserve Requirement of each Balancing Authority involved in the Assistance Period shall be updated to reflect the reduction of responsibility until the end of the Assistance Period.

i.g. All allocations shall be rounded to the nearest whole MW with a minimum of 2 MW and the smallest amount of energy to be allocated shall be one MWH.

j.h. After the contingency notification has been completed, the Contingency Area shall promptly make arrangements to replace the energy requirement created by the Operating Reserve Contingency (including its Contingency Reserve Allocation) prior to the end of the Assistance Period. The Contingency Area shall make a reasonable effort to purchase capacity and firm transmission service after utilization of its own resources.

k.i. If assistance is needed by the Contingency Area for a period of time longer than the initial Assistance Period, then this becomes an Other Extreme Condition and shall be reported as a separate contingency.

l. Each transmission provider shall immediately notify the SPP of the loss of transmission interconnection capability affecting its interchange transfer capability. The SPP shall update Group assignments for use during subsequent Assistance Periods. Each transmission provider is responsible for notifying the SPP once the contingency loss in the interchange transfer capability has been restored so that Group assignments can be updated.

m.j. For each reportable contingency (as defined by per the Operating Reliability Working Group section 6.4.4), the Contingency Area and Assisting Areas will send to SPP upon request, an electronic data file in a SPP specified format that records ACE, Frequency Deviation, Net Tie Deviation, and Net Interchange for 10 minutes prior to until 30 minutes after the contingency within two days of the SPP request for this data. If electronic data is not available, this data will be supplied on the NERC required charts.

<table>
<thead>
<tr>
<th>Proposed Tariff Language Revision</th>
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<th>Proposed Protocol Language Revision</th>
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Southwestern Power Administration Mr. Michael Wech
Oklahoma Gas & Electric        Mr. Greg Mcauley

Background
The SPP Reserve Sharing Group (RSG) made a change in June 2013 to move from a daily reserve obligation allocation process to an annual process. On December 19, 2013, or upon completion of the exit of several existing SPP RSG members, the ORWG has proposed to return to a daily assessment of the Total Contingency Reserve Obligation of the RSG as well as assignment of that obligation to the BA members of the RSG.

The proposed change would utilize the existing annual submission of System Peak Responsibility information to determine a pro-rata share among BA members of the Total Contingency Reserve obligation. That pro-rata ratio would remain fixed for the year June 1 to June 1. Daily, SPP will assess the capacity of the two largest units expected to be online for the following operating day and will determine the Total Contingency Reserve obligation of the RSG. That Total obligation will be allocated to the BA members of the RSG using the annually determined, fixed ratios. This change addresses the concern with economic implications related to carrying excess reserves when one or both of the typical two largest units are offline.

Analysis
In a meeting on September 11, 2013, the ORWG evaluated and approved the attached Criteria Revision Request #007 with a vote of 12 in favor, none opposed, no abstentions.

Recommendation
The MOPC recommends that the BOD approve the attached revision to Criteria 6 as noted in CRR007.

APPROVAL: MOPC October 15-16, 2013
Approved Unanimously
## Criteria Revision Request

<table>
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<td>007</td>
<td>Adjust Total Contingency Reserve Obligation Methodology</td>
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### Criteria Section(s) Requiring Revision

- **Section No.:** 6.3
- **Title:** Minimum Annual Daily Contingency Reserve Requirement

### Impact Analysis Required

- Yes – If yes, estimated cost: TBD

### Requested Resolution

- Normal
- No

### Type of Revision

- Correction/Clean-Up
- Clarification
- Policy Change

### Revision Description

Adjust the Total Contingency Reserve Methodology

### Reason for Revision

- Upon the occurrence of the significant membership changes to the RSG effective December 19, 2013 (or contingent upon the membership changes being effective), the impact of continuing the total contingency reserve obligation as equal to 100% of the largest + 50% of the second largest unit has been brought into question.

- Upon the membership change, the size difference between the largest and second largest units is greater than before the membership change. This results in a desire to re-adjust, on a daily basis, the total CR amount to reflect the daily maximum capability of the largest units.

### Tariff Implications or Changes

- Yes – Section No.: *(Include a summary of impact and/or specific changes)*

- No

### Protocol Implications or Changes

- Yes - Section No.: *(Include a summary of impact and/or specific changes)*

- No

### Date

9/11/2013

### Sponsor

<table>
<thead>
<tr>
<th>Name</th>
<th>Jason Smith</th>
</tr>
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<tbody>
<tr>
<td>E-mail Address</td>
<td><a href="mailto:jsmith@spp.org">jsmith@spp.org</a></td>
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<td>Southwest Power Pool</td>
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<tr>
<td>Phone Number</td>
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</table>
6.2.16 Reserve Sharing Group Annual Total Contingency Reserve Requirement
The minimum amount of Contingency Reserve that must be collectively carried by the Balancing Authorities participating in the SPP Reserve Sharing Group at a given time.

6.2.17 Balancing Authority Annual Contingency Reserve Requirement Ratio
A Balancing Authority member’s share of the total SPP Reserve Sharing Group System Peak Responsibility. The Balancing Authority’s Annual Contingency Reserve Requirement Ratio shall be determined by dividing the Balancing Authority’s System Peak Responsibility by the sum of all of the RSG member Balancing Authority’s System Peak Responsibilities. The minimum amount of Contingency Reserves that must be carried by each Balancing Authority during the stated year.

6.2.18 Balancing Authority Minimum Daily Contingency Reserve Requirement
A Balancing Authority member’s Contingency Reserve Requirement Ratio multiplied by the Reserve Sharing Group Total Contingency Reserve Requirement. Each Balancing Authority’s Daily Contingency Reserve Requirement shall be rounded up to the next nearest whole MW and shall be no less than two (2) MW.

6.3 Minimum Annual-Daily Contingency Reserve Requirement Calculation
The Operating Reliability Working Group (ORWG) will set the Minimum Annual-Daily Contingency Reserve Requirement for the SPP Reserve Sharing Group. The SPP Reserve Sharing Group will maintain a Minimum Annual-Daily Contingency Reserve, over and above any Regulating Reserves, equal to the generating capacity of the largest unit within the metered boundaries of any RSG member Balancing Authority plus one-half of the capacity of the next largest generating unit within the metered boundaries of any RSG member Balancing Authority. Any generation capacity additions, modifications or retirements may require that this Minimum Annual Contingency Reserve Requirement value be adjusted for the balance of the stated year. Generation capacity is considered to be added at the first injection of test power of the generator, regardless of commercial status.

If the SPP Reliability Coordinator foresees an operating condition in which reserves are inadequate to cover the Most Severe Single Contingency (MSSC), the SPP Reliability Coordinator has the authority to increase the total SPP Reserve Sharing Group Minimum Daily Contingency Reserve Requirement to the level necessary to cover the MSSC for the duration of the operating condition.

Any increased reserves that are based on non-compliance with the NERC Disturbance Control Standard will raise the total SPP Reserve Sharing Group Minimum Annual Contingency Reserve Requirement for the SPP Reserve Sharing Group on a quarterly basis. The Operating Reliability Working Group will determine the method by which the increased reserves will be allocated among the members of the SPP Reserve Sharing Group.

Each day, by 7:00am, the SPP Reliability Coordinator will notify each member Balancing Authority of its Daily Contingency Reserve Requirement for the following operating day.
6.3.1 Minimum Annual Balancing Authority Contingency Reserve Requirement Share Calculation

A member Balancing Authority’s Minimum Annual Contingency Reserve Requirement is equal to a prorated amount of the total SPP Reserve Sharing Group Minimum Annual Contingency Reserve Requirement as calculated per Criteria section 6.3. The Balancing Authority’s Minimum Annual Contingency Reserve Requirement shall be determined by dividing the Balancing Authority’s System Peak Responsibility as calculated per Criteria 2.1.6 by the sum of all of the RSG member Balancing Authority’s System Peak Responsibility and multiplying the resultant by the Annual Group Contingency Reserve Requirement. Each Balancing Authority’s Annual Contingency Reserve Requirement shall be rounded up to the next nearest whole MW and shall be no less than two (2) MW.

If the SPP Reliability Coordinator foresees an operating condition that reserves are inadequate to cover the Most Severe Single Contingency (MSSC), the SPP Reliability Coordinator has the authority to increase the total SPP Reserve Sharing Group Minimum Annual Contingency Reserve Requirement to the level necessary to cover the MSSC for the duration of the operating condition.

Any increased reserves that are based on non-compliance with the NERC Disturbance Control Standard will raise the total SPP Reserve Sharing Group Minimum Annual Contingency Reserve Requirement for the SPP Reserve Sharing Group on a quarterly basis. The Operating Reliability Working Group will determine the method by which the increased reserves will be allocated among the members of the SPP Reserve Sharing Group.

A member Balancing Authority whose historical information used as the basis of the Minimum Annual Contingency Reserve Requirement has changed significantly due to extreme circumstances may apply to the ORWG for a temporary waiver of all or a portion of its Minimum Annual Contingency Reserve Requirement. For example, the BA may request such a waiver due to (i) the shifting of load from one BA to another or (ii) drought conditions for Balancing Authorities whose system Capacity is comprised of more than 75% hydro based generation resources. ORWG will review such requests and make a recommendation to be considered by the MOPC at its next regularly scheduled meeting.

6.3.2 Minimum Annual Contingency Reserve Requirement Ratio Review Process

By May 1 each year, each Balancing Authority will submit to SPP its System Peak Responsibility as calculated per Criteria section 2.1.6 from the previous calendar year. SPP will calculate both the Reserve Sharing Group’s Total System Peak Responsibility Minimum Annual Contingency Reserve Requirement and each member Balancing Authority’s Minimum Annual Contingency Reserve Requirement Ratio. The results of these calculations will be presented for review and approval by the OWRG to be made effective June 1 of each year.

A member Balancing Authority whose historical information used as the basis of the Annual Contingency Reserve Requirement Ratio has changed significantly due to extreme circumstances may apply to the ORWG for a recalculation of its Annual Contingency Reserve Requirement Ratio. For example, the BA may request such a recalculation due to (i) the shifting of load from one BA to another or (ii) drought conditions for Balancing Authorities whose system Capacity is comprised of more than 75% hydro based generation resources. ORWG will review such requests and make a recommendation to be considered by the MOPC at its next regularly scheduled meeting.

<table>
<thead>
<tr>
<th>Proposed Tariff Language Revision</th>
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<thead>
<tr>
<th>Proposed Protocol Language Revision</th>
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Southwest Power Pool, Inc.
MARKETS AND OPERATIONS POLICY COMMITTEE
Recommendation to the Board of Directors

MPPRs 69, 101, 131, 132, 135, 138, 139, 140, 141, 149,

October 29, 2013

Organizational Roster
The following members represent the Market Working Group:

Richard Ross, AEP, Chairman
Gene Anderson, OMPA, Vice Chairman
Will Amos, OGE
Lee Anderson, Lincoln Electric System
Amber Metzker, Xcel Energy
Neal Daney, KMEA
Jim Flucke, KCPL
Clifford Franklin, Westar Energy, Inc.
Matt Johnson, City Utilities, Springfield, MO
Chris Lyons, Constellation Energy Commodities Group
Rick McCord, EDE
Matt Moore, Golden Spread Electric Cooperative
Aaron Rome, Midwest Energy, Inc.
Ann Scott, Tenaska Power Services Co.
Mike Swearingen, Tri-County Electric Cooperative, Inc.
Ron Thompson, NPPD
Bruce Walkup, AECC
Rick Yanovich, OPPD
Debbie James, SPP, Secretary

Background
Please see the MPRR Recommendation Report for MPPRs 69, 101, 131, 132, 135, 138, 139, 140, 141, 149 that were included in the MOPC October 15-16, 2013 background materials.

Analysis
Please see the MPRR Recommendation Report for MPPRs 69, 101, 131, 132, 135, 138, 139, 140, 141, 149 that were included in the MOPC October 15-16, 2013 background materials.

Recommendation
The MOPC recommends that the BOD approve its request regarding Marketplace Protocol Revision Requests MPPRs 69, 101, 131, 132, 135, 138, 139, 140, 141, 149

Action Requested: Approval of MWG’s request on MPPRs 69, 101, 131, 132, 135, 138, 139, 140, 141, 149

APPROVAL: MOPC October 15-16, 2013

Approved Unanimously-MPRR’S 069, 101, 132, 135, 138, 139, 140, 141, & 149

MPRR 131-Approved with Unanimously w/ 6 abstentions-ITC Great Plains, Xcel Energy, Calpine, Flat Ridge 2 Wind Energy, City of Coffeyville, & Exelon Power Team
<table>
<thead>
<tr>
<th>MPRR Number</th>
<th>Description</th>
<th>MWG Meeting Vote</th>
<th>RTWG Meeting Vote</th>
<th>ORWG Meeting Vote</th>
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<tr>
<td>69</td>
<td>Rules for Assets Pseudo-Tying</td>
<td>12/18/2012 Unanimously approved with modifications 1/22/2013</td>
<td>1/11/2013 Unanimously Approved with modifications subject to W&amp;T review 1/24/2013</td>
<td>1/9/2013 Approved</td>
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<td>8/6/2013 Unanimously approved RTWG’s modifications with further modifications</td>
<td>9/5/2013 Approved with modifications</td>
<td>8/30/2013 Approved</td>
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<td>101</td>
<td>Combined Cycle Enhanced Design</td>
<td>8/6/2013 Unanimously Approved</td>
<td>9/11/2013 Approved with modifications</td>
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<td>131</td>
<td>Settlements Related to PURPA Units</td>
<td>8/6/2013 Unanimously Approved</td>
<td>9/5/2013 Approved</td>
<td>8/30/2013 Approved with no Reliability Impact</td>
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<td>132</td>
<td>Reserve Sharing Group Registration and Settlements</td>
<td>7/23/2013 Approved</td>
<td>8/22/2013 Approved with modifications</td>
<td>8/15/2013 Approved with no Reliability Impact</td>
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<td>9/10/2013 Approved with RTWG modifications</td>
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<td>135</td>
<td>Settlements Clean-up and Clarifications</td>
<td>8/6/2013 Unanimously Approved</td>
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<td>138</td>
<td>Long Term Congestion Rights</td>
<td>8/6/2013 Unanimously Approved</td>
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<td>8/28/2013 Unanimously Approved</td>
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<td>139</td>
<td>Revenue Neutrality Correction</td>
<td>8/21/2013 Unanimously Approved</td>
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<td>8/30/2013 Approved with no Reliability Impact</td>
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<td>Mitigated Transition State Offers</td>
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<td>141</td>
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<td>149</td>
<td>Resources Not Qualified For Energy Correction</td>
<td>9/10/2013 Unanimously Approved</td>
<td>9/26/2013 Approved</td>
<td>9/12/2013 Approved with no Reliability Impact</td>
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# PRR Recommendation Report

<table>
<thead>
<tr>
<th>PRR No.</th>
<th>Marketplace-PRR69</th>
<th>PRR Title</th>
<th>Rules for Assets Pseudo-Tying</th>
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**Timeline**
- ☑ Normal  ☐ Expedited  ☐ Urgent Action
  
  Provide explanation if Expedited and/or Urgent Action is selected:

**Recommendation Action**
- ☑ Approve  ☐ Reject
  - ☐ Require additional information
  - ☐ Defer  ☐ Refer

**Impact Analysis Required**
- ☐ Yes – If yes, estimated cost:  ☑ No
  
  SPP Staff will complete this section.

**Protocol Section(s) Requiring Revision**
- Section No.: 4.2.2.5.7 (new), 4.5.9, 4.5.9.20, 4.5.12, 4.5.9.24 (new), 4.5.9.25 (new), 6.1.10, 6.1.11 (new), 6.1.12 (new), 6.2.2 (new), 6.2.3 (new), 6.2.4 (new)
  
  **Title:** Resources pseudo-tied Out of the SPP BA, Real-Time Balancing Market Settlement, Real-Time Over-Collecte losses Distribution Amount, Revenue Neutrality Uplift Distribution Amount, Real-Time pseudo-tie Congestion Amount, Real-Time pseudo-tie Losses Amount, Resources External to the SPP BA, Resources Internal to the SPP BA Pseudo-Tying Out, Operating Reserve Certification, Loads External to the SPP BA pseudo-tying In, Loads Internal to the SPP BA pseudo-tying Out, Non-Conforming Load

  **Protocol Version:** 8.0

**Type of Revision**
- ☐ Correction/Clean-Up  ☑ Clarification
  - ☐ Design Enhancement  ☑ Design Change

**Revision Description**

The proposed Protocol language changes are intended to detail the treatment of Resources or Loads that have pseudo-tied out of the SPP Balancing Authority. These Resources and Loads will need firm transmission and the necessary agreements signed between SPP, the MP and the External BA. In addition, these assets will be charged for congestion and losses based on the path of firm transmission of the pseudo-tied asset.

**Tariff Implications or Changes**

- ☑ Yes – Section No: *(Include a summary of impact and/or specific changes)*

  Attachment AE: 8.6.16 Real-Time Over-Collecte losses Distribution Amount, 8.6.19 Real-Time pseudo-tie Congestion Amount (new), 8.6.20 Real-Time pseudo-tie Losses Amount (new)

  Attachment AO modifications are included.

- ☐ No
### MWG Review

**PRR Recommendation**

<table>
<thead>
<tr>
<th>Date of Vote:</th>
<th>12/18/2012—Unanimously approved with modifications</th>
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<tbody>
<tr>
<td></td>
<td>1/22/2013—Unanimously approved RTWG’s modifications with further modifications</td>
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<tr>
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<td>8/6/2013 – Approved</td>
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<td></td>
<td>Abstain - NPPD</td>
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All Segments present for the vote: ☑ Yes ☐ No

Segment of Parties that voted No or Abstained: N/A

**Date of Vote:** 9/17/2013  **Vote:** Unanimously Approved RTWG modifications

**Opposed:** N/A  **Abstained:** N/A

### RTWG Review

| 1/11/2013—Approved with modifications subject to W&T review |
| 1/24/2013—Approved |
| 9/5/2013 – Approved with modifications |

### ORWG Review

| 1/9/2013—Approved |
| 8/30/2013 – Approved |

### MOPC Recommendation

| 1/15/2013—Approved |

### Board Review

| 1/29/2013—Approved |

**Date** 3/30/2012

### Sponsor

<table>
<thead>
<tr>
<th>Name</th>
<th>Carrie Simpson</th>
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<tbody>
<tr>
<td><strong>E-mail Address</strong></td>
<td><a href="mailto:csimpson@spp.org">csimpson@spp.org</a></td>
</tr>
<tr>
<td><strong>Company</strong></td>
<td>Southwest Power Pool</td>
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<tr>
<td><strong>Phone Number</strong></td>
<td>501.688.1757</td>
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### Comments Received

<table>
<thead>
<tr>
<th><strong>Comment Author</strong></th>
<th>Ron Thompson (NPPD)</th>
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<tr>
<td><strong>Date</strong></td>
<td>4/12/2012</td>
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<tr>
<th><strong>Comment Description</strong></th>
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<tr>
<td>NPPD would not be able to support MPRR69: NPPD does not believe SPP can force existing embedded load and resources in its BA that is not part of the SPP market to pseudo-tie out of the consolidated SPP BA. To Pseudo Tie out of SPP would require Firm Transmission Rights. The ability to get Firm Transmission is a lengthy process and likely would not be available by the start of the SPP Integrated Marketplace. With this in mind this MPRR would not address the embedded Load and Generation by the start of the SPP Integrated Marketplace if that entity wanted to Pseudo Tie out of SPP. Also NPPD has concerns with the language Resources and Load internal to SPP BA not wishing to participate in the SPP. NPPD would like to discuss the procedure that SPP would have that would require the Resource to Pseudo Tie out of the SPP BA.</td>
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<tr>
<th><strong>Comment Status</strong></th>
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<tr>
<td>Comments were taken into consideration. The approved language is reflected in this recommendation report.</td>
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<td>Comments Received</td>
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<td><strong>Comment Author</strong></td>
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<td><strong>Date</strong></td>
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<td><strong>Comment Description</strong></td>
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the Tariff, Section 2.2(10), RTWG reworded the first sentence because the meaning of the word "Entities" was unclear. RTWG made further non-substantive clarifications and grammatical changes and added section references. In Attachment AO, RTWG changed “non-physical” to “pseudo-tie” for clarity since “non-physical” is only part of the definition of “pseudo-tie”. “Resource” was changed to “generator” in Attachment AO. Further minor clarifications were made, and unnecessary portions of AO were removed. No intent was changed in Attachment AO or the Tariff.

Comment Status
The MPRR was approved as modified. The approved language is reflected in this recommendation report.

Comments Received
Comment Author
Jared Greenwalt on behalf of MWG
Date
1/25/2013
Comment Description
MWG approved RTWG’s modifications and added the following modifications. In the Tariff, Section 2.2(10), they added “Market Participants with assets” instead of “Entities owning assets” because “Market Participants” is used on Attachment AO. In Attachment AO, “Pseudo-Tie” and its derivatives were changed from capital to lower case.

Comment Status
The MPRR was approved as modified. The approved language is reflected in this recommendation report.

Comments Received
Comment Author
Debbie James
Date
7/19/2013
Comment Description
These comments add the requirement that MPs must be the meter agent or may designate a meter agent. Also, if pseudo-tied Resources are added or removed, then MPs must adhere to registration lead times. In addition, a Resource associated with a pseudo-tie must reduce its output if the pseudo-tie is reduced or unavailable for reliability reasons. These comments update references and update the language so that the changes are made on top of Protocols 15.0a. Language was added to Section 4.5.9.1 (Real-Time Asset Energy Amount) to explain that pseudo-tied Resource are not part of the hourly residual load. These comments will make MPRR69 Go-Live.

Comment Status
The MPRR was approved as modified. The approved language is reflected in this recommendation report.

Comments Received
Comment Author
Mark McGrail (EGPNA)
Date
8/2/2013
Comment Description
EGPNA does not support MPRR69 as proposed:

This protocol, as proposed, limits the viable commercial options made available to our contracted power purchasers of Renewable Energy as compared to other Market Participants.

EGPNA would be unable to manage the commercial risks associated with our power purchase agreement for the Caney River Wind Project.

Alabama Power, who is the ultimate customer for Chisholm View and Buffalo Dunes wind energy, would be unable to mitigate risks and abide by the contractual
arrangements in our power purchase agreements.

**Issues:**

Manage Risks associated with Power Purchase Agreement contractual obligations.

1. **Adverse Economic Conditions** – the proposed protocol unfairly limits the Market Participant’s ability to manage the congestion risk associated with the transmission of energy. For example, if congestion costs spike, as a pseudo tied resource, we are not provided any alternatives to redirect our energy to another off-taker or to the imbalance market. Under the current proposal, we would be prevented from delivering to the imbalance market, as we would not receive a market based rate but instead we would be forced to deliver for $0 or to curtail.

2. **System Operating Constraints** – the proposed protocol unfairly limits the Market Participant’s ability to manage the physical risks associated with the transmission of energy. For example, if there is a system constraint at the sink of the transmission path, similar to the example above we are prevented redirecting or delivering our energy to a viable energy market.

Manage Risks associated with the normal pseudo tie operations

This MPRR proposes that a Market Participant with a pseudo-tie not be compensated for unavoidable surplus imbalance energy caused by standard pseudo tie calculations, electronic systems or communications failures.

In summary, MPRR69, unfairly limits a Market Participant’s ability to manage the contractual obligations and the risks associated with energy delivered from Renewable Resources. We recognize that at times Renewable Resources provide challenges for Real Time System Operators, which is why we provided contractual flexibility to manage the Renewable Resource output. It is our opinion, that the flexibility provided for in today’s EIS Market should be maintained to support the continued development of Renewable Resources in the SPP footprint.

At this time, we are not proposing new language to the MPRR69, but ask that the Market Working Group table any decision regarding pseudo tie out resources until such time that the commercial issues can be fully vetted for all affected parties.

**Comment Status**

Comments were taken into consideration. MWG did not make any changes based on the comments received.

**Comments Received**

<table>
<thead>
<tr>
<th>Comment Author</th>
<th>James Sweatt (SWE MP)</th>
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<tr>
<td>Date</td>
<td>8/2/2013</td>
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</table>

**Comment Description**

Southern Company Services, Inc. (SWE MP) does not support MPRR69 as proposed as it does not allow appropriate mitigation of the commercial risks associated with a resource that is pseudo-tied out of SPP.

There are certain risks for a pseudo-tie resource that are beyond the Market Participant’s control. For example, in the event of an operating constraint that limits the receiving balancing authority’s ability to receive the energy the Market Participant, under the proposed revision, would not have the ability to sell generation to SPP or any other counterparty.
In addition, this proposed MPRR severely restricts a Market Participant’s ability to limit negative financial impacts of congestion charges along a pseudo-tie path. Although ARR/TCR markets are intended to provide a way for Market Participants to hedge congestion costs, it is difficult or impossible to match intermittent resource generation with an appropriate TCR profile. During periods of very high congestion costs, a pseudo-tie Market Participant needs the ability to participate in SPP’s Integrated Marketplace.

Further, in the event of a system or communication failure at SPP or other transmitting entity that causes imbalance to occur, the proposed MPRR would not allow the Market Participant to be compensated for imbalance energy.

There are no specific language proposals to MPRR69. Instead we ask that SPP work with us prior to making a final decision on this protocol revision to find an acceptable solution for the issues above.

Comments were taken into consideration. MWG did not make any changes based on the comments received.

The RTWG reviewed MPRR69 and made some updates. In section 2.2 of Attachment AE of the Tariff, the RTWG made some changes to (14). This new language added helps to clarify what happens with the pseudo-tie if the BA can no longer maintain the pseudo-tie Resource. Language was added and changed throughout the Tariff to clean up grammatical errors.

All RTWG changes are highlighted in yellow.

4.2.2.5.6 Non-Dispatchable Variable Energy Resources
The following rules apply to Resources registered as Non-Dispatchable Variable Energy Resources (“NDVER”):

1. For the RUC processes, the maximum operating limit shall be as submitted in the Resource Offer;

2. For the Real-Time Balancing Market, the Resource’s Energy Offer Curve shall not apply and offer prices shall be assumed equal to zero for the purposes of calculating production costs relating to RUC make-whole payments and cost allocation thereof under Sections Error! Reference source not found. and Error! Reference source not found.. The
Resource must operate in “Manual” Control Status and the Setpoint Instruction will be an echo of actual SCADA output as updated every ten seconds.

4.2.2.5.7 External Dynamic Resource

Any external Resource, not pseudo-tied, or external fleet of resources that will be participating in the Energy and Operating Reserve Markets will be modeled and registered as an External Dynamic Resource (“EDR”). EDRs in the Eastern Interconnection are not permitted to offer Energy but may elect to fix their Energy output through the use of a Dynamic Schedule. EDRs associated with DC Ties may only be modeled and registered as an EDR if the DC tie is continuously dispatchable across zero. Dead bands are not supported. The following specific rules pertain to EDRs: …

4.2.2.5.8 Resources Pseudo-Tied Out of the SPP BAA

The following rules apply to Resources physically located within the SPP BAA that have pseudo-tied out of the SPP BAA:

(1) The Resource must be registered as described under Section 6.1.10.2;

(2) For the DA Market, RUC, and RTBM processes, none of the requirements and options relating to Resource Offer parameters described under Section 4.2.2.1 shall apply;

(3) For the RTBM, the Resource output will be included in the current RTBM analysis as an echo of actual output, and the Resource will be charged for marginal losses and congestion costs between the Resource PNode and the applicable External Interface Settlement Location as described under Sections 4.5.9.2.c and 4.5.9.2.d.

(4) If the pseudo-tie associated with the Resource becomes reduced or unavailable due to reliability issues within the SPP Balancing Authority or associated external Balancing Authority, the Resource associated with the pseudo-tie must immediately limit its output to the available pseudo-tie capability. After receiving notification from the affected Balancing Authority of the reduced capability, a Market Participant shall not generate energy in excess of the pseudo-tie capability. A Market Participant shall not be compensated for such energy in the Integrated Marketplace.

4.2.2.6 Virtual Energy Offers

Virtual Energy Offers are supported in the DA Market only. Virtual Energy Offers are purely financial, only apply to Energy and are not associated with a physical Resource asset. The following rules apply to Virtual Energy Offer submittal.
4.2.3 Bid Submittal

Beginning seven (7) days prior to the Operating Day, Market Participants are expected to begin submitting Demand Bids and Virtual Energy Bids for the purchase of Energy in the DA Market and/or Export Interchange Transaction Bids for the purchase of Energy in the DA Market or RTBM. The following business rules apply to Bid submittal:

1. Bid submittal other than for a fixed Export Interchange Transaction Bid does not apply to any of the RUC processes or the RTBM;
2. Submitted Bids do not roll forward hour to hour;
3. Demand Bids may only be submitted at Load Settlement Locations, Export Interchange Transaction Bids may only be submitted at External Interface Settlement Locations; Virtual Energy Bids may be submitted at any Settlement Location, including a Hub;
4. Bid submittal for use in the DA Market is voluntary.
5. Bid submittal associated with a load pseudo-tied out of the SPP BA is not permitted.

4.2.3.1 Demand Bids

Only Market Participants with registered load assets may submit Demand Bids for use in the DA Market. Demand Bids are associated with physical load assets. The following rules apply to Demand Bid submittal:

1. A Market Participant can only submit Demand Bids for the registered load Settlement Location of the Asset Owner(s);
2. A Market Participant is not permitted to submit a Demand Bid for a load asset pseudo-tied out of the SPP BA.
3. Two types of Demand Bids will be supported: Fixed and Price Sensitive;
   a. A Fixed Demand Bid is a specified MW that will be cleared in the DA Market regardless of the price at the Load Settlement Location based on the start and stop time submitted for the applicable Operating Day.
   b. A Price Sensitive Demand Bid is specified as a Demand Bid Curve (MW, $/MWh, up to 10 price/quantity pairs, slope or block option, block and slope pairs may not coexist – the Resource Offer in effect for any given period of time must be comprised of all block or all slope price/quantity pairs) that will clear only if the price at the Load Settlement Location is less than or equal to the specified curve price within the specified start and stop time submitted for the applicable
Operating Day with the highest MW quantity submitted in the Demand Bid Curve representing the maximum MW amount that can be cleared.

### 4.5.9 Real-Time Balancing Market Settlement

Settlement calculations for the Real-Time Balancing Market are performed on a Dispatch Interval basis for each Operating Day and are based upon the difference between the results of the RTBM process and the DA Market clearing for that Operating Day. To calculate RTBM actual Energy in a Dispatch Interval for Asset Owners that have not directly submitted 5-minute interval meter data, SPP allocates the submitted hourly meter data for Resources and loads into 5-minute values using 5-minute telemetered or State Estimator profiles for the corresponding hour. The profiling of the hourly meter data maintains the shape of the 5-minute telemetered or State Estimator values even if there are both positive and negative values contained within the 12 intervals. All Dispatch Interval values are expressed in MW, not MWh. Exhibit 4-19 shows an example of how the profiling will work for a Resource that submits an actual hourly meter amount of -80 MWh.

**Exhibit Error! No text of specified style in document.-1: Meter Profiling Example**

<table>
<thead>
<tr>
<th>Interval</th>
<th>(1) State Estimator MW</th>
<th>(2) Absolute Value of Column (1)</th>
<th>(3) Normalize Column (2) [Col (2) MW / Total Col (2) MW]</th>
<th>(4) Profiled Hourly Meter (-80 – (-66.25)) * 12 * Col (3) + Col (1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>10</td>
<td>10</td>
<td>0.012</td>
<td>8</td>
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<tr>
<td>2</td>
<td>5</td>
<td>5</td>
<td>0.006</td>
<td>4</td>
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<tr>
<td>3</td>
<td>0</td>
<td>0</td>
<td>0.000</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>-50</td>
<td>50</td>
<td>0.061</td>
<td>-60</td>
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<tr>
<td>5</td>
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<td>60</td>
<td>0.073</td>
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<tr>
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<tr>
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<td>9</td>
<td>-100</td>
<td>100</td>
<td>0.121</td>
<td>-120</td>
</tr>
<tr>
<td>10</td>
<td>-110</td>
<td>110</td>
<td>0.133</td>
<td>-132</td>
</tr>
<tr>
<td>11</td>
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<td>0.145</td>
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</tr>
<tr>
<td>12</td>
<td>-130</td>
<td>130</td>
<td>0.158</td>
<td>-156</td>
</tr>
<tr>
<td>-66.25 MWh</td>
<td>825 (total)</td>
<td></td>
<td>1.000</td>
<td>-80 MWh (Meter) (submitted)</td>
</tr>
</tbody>
</table>
RTBM results are presented on an hourly basis but Market Participants and Asset Owners have access to the 5 minute data for verification purposes.

(1) Each Market Participant with actual Resource output is charged or paid for each Settlement Location for the difference between the amount of actual RTBM physical Energy sold and the amount of physical Energy sold in the DA Market, net of Bilateral Settlement Schedules for Energy, at the associated RTBM LMP (see Section Error! Reference source not found.);

(2) Each Market Participant with Import Interchange Transactions or Through Interchange Transactions (Resource Node) is charged or paid for each Settlement Location for the difference between the amount of actual RTBM physical import Energy scheduled and the amount of physical Energy sold in the DA Market, net of Bilateral Settlement Schedules for Energy, at the associated RTBM LMP (see Section Error! Reference source not found.);

(3) Each Market Participant with virtual Energy purchased in the DA Market is paid for the amount of virtual Energy purchased in the DA Market at the associated RTBM LMP (see Section Error! Reference source not found.);

(4) Each Market Participant with cleared Operating Reserve Offers is charged or paid for each Settlement Location:

   (a) For the difference between the amount of Regulation-Up sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Regulation-Up MCP (see Section Error! Reference source not found.);

   (b) For the difference between the amount of Regulation-Down sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Regulation-Down MCP (see Section Error! Reference source not found.);

   (c) For the difference between the amount of Spinning Reserve sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Spinning Reserve MCP (see Section Error! Reference source not found.); and

   (d) For the difference between the amount of Supplemental Reserve sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Supplemental Reserve MCP (see Section Error! Reference source not found.).
(5) Each Market Participant with actual load consumption is charged or paid for each Settlement Location for the difference between the amount of actual physical load purchased and the amount of physical Energy purchased in the DA Market, net of Bilateral Settlement Schedules for Energy, at the associated RTBM LMP (see Section Error! Reference source not found.).

(6) Each Market Participant with Export Interchange Transactions or Through Interchange Transactions (Load Node) is charged or paid for each Settlement Location for the difference between the amount of actual physical export Energy scheduled and the amount of physical export Energy purchased in the DA Market, net of Bilateral Settlement Schedules for Energy, at the associated RTBM LMP (see Section Error! Reference source not found.).

(7) Market Participants with SPP committed Resources in any of the RUC processes that were not committed in the DA Market may receive a make whole-payment if the total revenues received for Energy and Operating Reserve sales in the RTBM settlement are less than the Resource’s Offer costs. See Section Error! Reference source not found. for calculation details. Certain costs are not eligible for recovery as follows:

   (a) If the Resource operates outside of its Operating Tolerance in a Dispatch Interval, costs associated with Energy provided in excess of the Resource’s Desired Dispatch are not eligible for recovery in that Dispatch Interval;

   (b) If Resource is in “Manual” Control Status in a Dispatch Interval, costs associated with Energy provided in excess of the Resource’s Desired Dispatch are not eligible for recovery in that Dispatch Interval; and

   (c) If the Resource increases its minimum limits in a Dispatch Interval above the minimum limits used by SPP to make the commitment decision by more than the Resource’s Operating Tolerance, costs associated with Energy provided in excess of the Resource’s Desired Dispatch are not eligible for recovery in that Dispatch Interval.

(8) Make-Whole payments for SPP committed Resources as described in (7) above are collected on a daily basis from Market Participants based upon their pro-rata share of the sum of following quantities for the Operating Day as described in detail under Section Error! Reference source not found.:

   (a) The absolute value of the net Settlement Location deviations from DA Market cleared amounts for load, virtual transactions and interchange transactions –
excluding deviations resulting from actual load consumption that is less than DA Market cleared load MWh during capacity shortage condition Emergencies;

(b) The positive difference between RTBM Resource minimum limits and DA Market Resource minimum limits, subject to exclusion if certain criteria are met;

(c) The positive difference between the DA Market Resource maximum limits and the RTBM Resource maximum limits, subject to exclusion if certain criteria are met;

(d) A Resource’s DA Market cleared amount if that Resource is off-line in the RTBM, subject to exclusion if certain criteria are met;

(e) The absolute value of the difference between a Resource’s actual output and the Resource’s Desired Dispatch quantity if Resource is in “Manual” Control Status;

(f) The actual Resource output for Resources that self-committed following the close of the DA Market, subject to exclusion if certain criteria are met;

(g) A Resource’s Desired Dispatch quantity for Resources that were committed following the close of the DA Market if that Resource is off-line in the RTBM, subject to exclusion if certain criteria are met; and

(h) The absolute value of a Resource’s Uninstructed Resource Deviation if that Resource operated outside of its Operating Tolerance, subject to exclusion if certain criteria are met.

(9) In addition, Resources may receive a make-whole payment related to a Manual Dispatch Instruction as described under Section Error! Reference source not found., subject to certain eligibility requirements, as follows:

(a) If the Resource is issued a Manual Dispatch Instruction by SPP in any hour that creates Out Of Merit Energy (OOME) in excess of the Resource’s Dispatch Instruction and the Resource Offer costs associated with the OOME are greater than the Energy revenue received for the OOME, the Resource will receive the difference between the Energy Offer Curve costs associated with the OOME and the OOME Energy revenue;

(b) If the Manual Dispatch Instruction is for Energy in the down direction and the RTBM LMP is greater than the DA Market LMP, the Asset Owner will receive a credit for the difference multiplied by the OOME MW. The OOME MW is
calculated as Max (0, the difference between the Resource’s DA Market cleared Energy MW and actual Resource output); and

(c) If during the Manual Dispatch Instruction, the RTBM cleared amount of an Operating Reserve product is less than the DA Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the DA Market MCP, the Asset Owner will receive a credit for the difference multiplied by the OOMOR MW. The OOMOR MW is calculated as Max (0, the difference between the Resource’s DA Market cleared Operating Reserve MW and the Resource’s RTBM cleared Operating Reserve MW).

Make-whole payments associated with OOME are collected as part of revenue neutrality uplift as described under Section 4.5.12.

(10) Charges for failure to deploy Regulation-Up or Regulation-Down and charges for failure to deploy the specified amount of cleared Spinning Reserve or Supplemental Reserve are collected from Market Participants as part of the RTBM settlement as described under Sections Error! Reference source not found. and Error! Reference source not found. are distributed to Market Participants on a load ratio share basis as described under Sections Error! Reference source not found. and Error! Reference source not found.;

(11) Charges to Market Participants for RTBM Operating Reserve procurement costs are collected on a Real-Time load ratio share basis as described under Sections Error! Reference source not found., Error! Reference source not found., Error! Reference source not found., Error! Reference source not found.;

(12) Resources providing Regulation-Up and/or Regulation-Down deployment will receive a credit or charge associated with the regulation deployment energy as described under Section Error! Reference source not found. such that Resources maintain Energy margins that are equal to the Energy margins that would have been attained absent the regulation deployment;

(a) For Regulation-Up, a credit is calculated if the cost rate of the Regulation-Up Energy is greater than the associated LMP and a charge is calculated if the associated LMP is greater the Regulation-Up Energy cost rate;¹

¹ A charge is calculated here because this difference (opportunity cost) has already been included in the Regulation-Up MCP.
(b) For Regulation-Down, a credit is calculated if the associated LMP is greater than the cost rate of the Regulation-Down Energy and a charge is calculated if the cost rate of the Regulation-Down Energy is greater than the associated LMP.\(^2\)

(13) Settlement associated with revenue mismatch due to the impact of marginal losses on the RTBM LMPs is also performed as part of the RTBM settlement as follows. See Section 4.5.9.20 for calculation details;

(a) For each Asset Owner, a proxy loss charge contribution amount is developed for each Settlement Location with a net RTBM withdrawal (RTBM actual – DA Market cleared amount) that is equal to the sum of i) the positive difference between the MLC at the net withdrawal Settlement Location and the weighted average MLC of all net injections (RTBM actual – DA Market cleared amount) assumed to be serving the net withdrawal, multiplied by that Asset Owner’s share of the net withdrawal, where that share is calculated excluding cleared Virtual Bids and cleared Virtual Offers and ii) the sum of charges for Real-Time \(\text{pseudo-tie Losses at the Settlement Location of the Sink of the pseudo-tie path}\);

(i) The net injections assumed to be serving the net withdrawal are the net injections at the Settlement Locations included in that Asset Owner’s Loss Pool. The Asset Owner’s Loss Pool is defined dynamically and includes all Settlement Locations at which that Asset Owner has transactional activity (Bilateral Settlement Schedules, Resource output, load consumption, Interchange Transactions), but excludes virtual transactions. To the extent that the net injections in the Asset Owner’s Loss Pool are not sufficient to serve the net withdrawals in the Asset Owner’s Loss Pool, net injections from an injection exchange are included to make up the difference. To the extent that the net injections in the Asset Owner’s Loss Pool are greater than the net withdrawals in the Asset Owner’s Loss Pool, the excess is added to the injection exchange;

(ii) The injection exchange is comprised of quantities from Loss Pools in which injection exceeds withdrawal. A weighted average of the MLC at the source of these quantities establishes a reference for the component of the loss charge contributions at Settlement Locations with net withdrawal met from outside the Asset Owner’s Loss Pool.

\(^2\) A charge is calculated here because this difference has already been included in the Regulation-Down MCP.
(b) Each Asset Owner’s credit or charge (all Asset Owner net withdrawals at Settlement Location participate) associated with RTBM over collected losses (which may be either an over collection or under collection) is then equal a pro-rata share of the total marginal losses over collection or under collection as calculated from the proxy loss charge contribution calculated in (a) above.

(14) Settlement (charges or credits) associated with services provided under Joint Operating Agreements are described under Section 4.5.9.21. These Charges or credits are collected or distributed as part of revenue neutrality uplift as described under Section 4.5.12;

(15) Settlement (charges or credits) associated with Contingency Reserve deployment involving Reserve Sharing Group members is accounted for as described under Section 4.5.9.22. These charges or credits are collected or distributed on a load ratio share as described under Section 4.5.9.23.

(16) Demand reduction credits to Market Participants associated with a load Settlement Location that contains a Demand Response Resource are calculated as part of the RTBM settlement in order to ensure that, on a net settlement basis, the RTBM charge associated with that load Settlement Location is reflective of the net load (i.e. the load including the impact of a cleared Demand Response Resource).

For example, consider a load Settlement Location that consists of a single PNode and that PNode also represents a Demand Response Load that is associated with a Dispatchable Demand Response (DDR) Resource. The Market Participant for the load Settlement Location submits a fixed Demand Bid in the Day-Ahead Market of 100 MW, which is reflective of that location’s actual load consumption in real-time, assuming that there is no load reduction (i.e. this value represents the baseline value for the DRL that will be submitted for use in real-time). The Market Participant for the DDR Resource submits a Resource Offer that results in the DDR clearing for 20 MWs of Energy (resulting in a net Day-Ahead Market cleared load of 80 MW).

For the corresponding hour in real-time, the DDR actual output was 25 MWs and the actual submitted meter value of the DRL was 75 MW. However, to ensure proper accounting for deviations in real-time load from cleared Day-Ahead Market amounts and calibration calculations, the submitted DRL actual meter value must be grossed up by the amount of DDR output. If we assume that RTBM LMP is $50/MWh, the net settlement at the load Settlement Location would be:

**Load Settlement:** \( \{(75 \text{ MW} + 25 \text{ MW}) - (100 \text{ MW (DA Market)}\} \times 50/\text{MWh} = 0 \)
\[
\text{Demand Reduction Amount (Credit)} = (-25 \text{ MW} - (-20 \text{ MW (DA Market)}) \times \$50/\text{MWh} = (-250) \\
\text{Net Load Settlement Location Settlement} = (-250)
\]

The net ($250) credit is the same as the credit that would have been calculated using the net RTBM load of 75 MW and the net cleared Day-Ahead Market load of 80 MW in the RTBM settlement ((75 MW – 80 MW) multiplied by the $50/MWh LMP). However, in order to ensure proper deviation and calibration accounting in real-time, the 100 MW of cleared load and the 25 MW of cleared DDR output is used to calculate real-time deviations from cleared Day-Ahead Market amounts and calibration energy amounts. See Section 4.5.9.24 for additional calculation details.

(17) Charges or credits to Market Participants for allocation of RTBM demand reduction amounts are calculated on a system-wide basis by multiplying the demand reduction rate by each Market Participant’s RTBM demand reduction obligation. See Sections 4.5.9.25 for additional details;

(a) The demand reduction rate is equal to the total of demand reduction amounts calculated for load divided by the system-wide total actual withdrawals (real-time metered load and export transactions).

(b) Each Market Participant’s demand reduction obligation is equal to that Market Participant’s total actual withdrawals (real-time metered load and export transactions).

(18) Settlements (charges or credits) for congestion and losses associated with Resources or load internal to the SPP footprint that has pseudo-tied out of the SPP Balancing Authority, is accounted for as described under Sections 4.5.9.2 and 4.5.9.27.

The following subsections describe the RTBM settlement charge types in more detail. For each charge type, the initial calculation is performed either at the Dispatch Interval level or hourly level for each Asset Owner at each Settlement Location. In addition to the Dispatch Interval and hourly values, hourly and daily values will be accessible on the Settlement Statement for all charge types.

4.5.9.1 Real-Time Asset Energy Amount

(1) The Real-Time Asset Energy Amount can be either a credit to an Asset Owner or a charge to an Asset Owner and is calculated on a net basis at each Settlement Location for:
(a) the difference between actual metered supply MWh amounts in a Dispatch Interval and cleared Resource Offers in the DA Market;

(b) the difference between actual metered demand MWh amounts in a Dispatch Interval and all cleared Demand Bids in the DA Market; and

(c) Real-Time Bilateral Settlement Schedules for Energy in a Dispatch Interval.

The net amount to each Asset Owner (AO) for each Settlement Location in a Dispatch Interval is calculated as follows:

\[
\text{#RtEnergy5minAmt}_{a,s,i} = \text{RtLmp5minPrc}_{s,i} \times \left[ \text{RtBillMtr5minQty}_{a,s,i} - \text{DaClrdHrlyQty}_{a,s,h} \right] - \sum_i \text{RtEnFinHrlyQty}_{a,s,t,h} / 12
\]

Where,

(a) The 5-minute billable meter determinant at the Settlement Location level is the sum of the 5-minute billable meter determinants at the Meter Data Submittal Location level as shown in the formula below. Most Settlement Locations will be comprised of only one Meter Data Submittal Location, but in certain cases a single Settlement Location will represent multiple Meter Data Submittal Locations, each of which is in a separate Settlement Area. Since the calibration function must be performed within Settlement Area boundaries, it is done before summing the data to the Settlement Location level. The 5-minute determinants are expressed in terms of levelized MW at both the Settlement Location and Meter Data Submittal Location level.

\[
\text{RtBillMtr5minQty}_{a,s,i} = \sum_{ml} \text{RtMlBillMtr5minQty}_{a,ml,i}
\]

(b) The 5-minute billable meter determinant at the Meter Data Submittal Location level is the sum of the 5-minute adjusted meter determinant and the 5-minute calibration meter determinants at the Meter Data Submittal Location level as shown in the formula below. Both 5-minute determinants are expressed in terms of levelized MW.
\[ \text{RtMBlMtr5minQty}_{a, ml, i} = \]
\[ \text{RtAdjMtr5minQty}_{a, ml, i} + \text{RtCalMtr5minQty}_{a, ml, i} \]

(c) For Resource and load assets, the 5-minute adjusted meter determinant is a hierarchal selection among 1) 5-minute submitted actual meter reading, 2) profiled hourly submitted actual meter reading and 3) default 5-minute state estimator value. Registration will determine whether 5-minute or hourly meter submittals are permitted – it will not allow both for any given period. Under the Marginal Loss approach, it is assumed that meter submissions, with the exception of those with a “top-down load” relationship to the Settlement Area – generally those for which a top-down calculation is used – are net of transmission losses. Losses will be backed out of load submittals for the “top-down load”. For Demand Response Resources, the hierarchy is the same for submitted data, but instead of defaulting to the State Estimator data, the Resource output is calculated as the difference between a) the minimum of i) the hourly baseline load submitted for the Demand Response Load and ii) the State Estimator snapshot for the Demand Response Load for the 5 minute interval immediately preceding the first dispatch interval (i = -1) and b) the Adjusted Meter Quantity for the DRL for each 5 minute interval. Registration will determine whether meter submittals are permitted or if the Demand Response resource must rely solely on the calculated resource output. For loads in which a Demand Response resource is imbedded within a Settlement Location, the response is added to the load meter data “grossing-up” the MW to avoid double counting of the response. In cases where load is calculated via a “top-down load” method (usually for the top-down load entity in the Settlement Area), gross-up is not necessary if the response is included with other generation from which interchange, metered load and losses are netted to achieve the submitted load introducing deviation between DA Market cleared Energy and the billable meter quantity. 5-minute adjusted meter, state estimator, SCADA and gross-up determinants are expressed in terms of levelized MW and both hourly and 5-minute submitted actual determinants are in terms of MWh. The formula for the 5-minute adjusted meter determinant is shown below.

IF EXISTS \{ \text{RtActMtr5minQty}_{a, ml, i} \} THEN

\[ \#\text{RtAdjMtr5minQty}_{a, ml, i} = \]
\[
RtActMtr5minQty_{a, ml, i} \times 12 + RtLoadGrossUp5minQty_{a, ml, i}
- \{ \text{IF TOPDOWNLOAD(ml) THEN } RtSELoss5minQty_{sa, i} , \text{ ELSE } 0 \} 
\]

ELSE

IF EXISTS \{ RtActMtrHrlyQty_{a, ml, h} \} THEN

\[
#RtAdjMtr5minQty_{a, ml, i} = RtSE5minQty_{a, ml, i}
+ \{ (RtActMtrHrlyQty_{a, ml, h} - \sum_i RtSE5minQty_{a, ml, i} / 12)
\]

* \{ IF (\sum_i ABS(RtSE5minQty_{a, ml, i}) > 0 \text{ THEN } \{ABS(RtSE5minQty_{a, ml, i}) / \sum_i ABS(RtSE5minQty_{a, ml, i})\} , \text{ ELSE } 1 \} * 12 \}

+ RtLoadGrossUp5minQty_{a, ml, i}
- \{ \text{IF TOPDOWNLOAD(ml) THEN } RtSELoss5minQty_{sa, i} , \text{ ELSE } 0 \} 
\]

ELSE

IF \{ DRR \} THEN

\[
#RtAdjMtr5minQty_{a, ml, i} = 
\text{MAX} [\text{MIN} (\text{RtBaseLineHrlyQty}_{a, ml(drl), h} , RtSE5minQty_{a, ml(drl), i = -1} ) - \text{RtAdjMtr5minQty}_{a, ml(drl), i} , 0 ] * (-1)
\]

ELSE

\[
#RtAdjMtr5minQty_{a, ml, i} = 
\]

\[
RtSE5minQty_{a, ml, i} + RtLoadGrossUp5minQty_{a, ml, i}
\]

(d) The 5-minute load gross-up determinant is the inverse of the 5-minute adjusted meter determinant for the Demand Response resource which is behind the meter of the load. The 5-minute load gross-up determinant is expressed in terms of
levelized MW. The formula for the 5-minute load gross-up determinant is shown below.

\[
RtLoadGrossUp5minQty_{a, ml, i} = \sum_{ml(drr)} \text{RtAdjMtr5minQty}_{a, ml(drr), i} \cdot (-1)
\]

(e) The 5-minute calibration meter determinant is the hourly quantity, profiled by State Estimator data into 5-minute intervals as shown in the formula below. The 5-minute calibration meter determinant is expressed in terms of levelized MW. The formula for the 5-minute calibration meter determinant is shown below.

\[
#RtCalMtr5minQty_{a, ml, i} = \text{RtSE5minQty}_{a, ml, i} + \left\{ (\text{RtCalMtrHrlyQty}_{a, ml, h} - \sum_i \text{RtSE5minQty}_{a, ml, i} / 12) \right. \\
\left. \cdot \left[ \frac{\text{ABS}(\text{RtSE5minQty}_{a, ml, i})}{\sum_i \text{ABS}(\text{RtSE5minQty}_{a, ml, i})} \right] \right\} \cdot 12
\]

(f) The hourly calibration meter determinant is the weighted distribution of Settlement Area residual among load in the Settlement Area (excluding Resources and load pseudo-tied into SPP, but not accounted for in the submittal of interchange of any Settlement Area). The hourly calibration meter determinant is expressed in terms of levelized MW. The formula for the hourly calibration meter determinant is shown below.

\[
\text{IF} \text{IsPsgiPsl} (ml) \text{THEN}
\]

\[
#\text{RtCalMtrHrlyQty}_{a, ml, h} = 0
\]

\[
\text{ELSE}
\]

\[
#\text{RtCalMtrHrlyQty}_{a, ml, h} = \text{RtResMtrHrlyQty}_{sa, h} \cdot \left[ \max \left( \text{RtAdjMtrHrlyQty}_{a, ml, h}, 0 \right) \right]
\]
(g) The hourly adjusted meter determinant is the sum of the 5-minute adjusted meter determinant divided by 12. The hourly adjusted meter determinant is expressed in terms of levelized MW. The formula for the hourly adjusted meter determinant is shown below.

$$\sum_{ml} \text{MAX} \left( \text{RtAdjMtrHrlyQty}_{a, ml, h} , 0 \right)$$

(h) The hourly residual load determinant is the net difference between generation & load, excluding Resources and load pseudo-tied into SPP, but not accounted for in the submittal of interchange of any Settlement Area, interchange and losses per Settlement Area. Hourly Net Actual Interchange is derived as the sum of the hourly metering submitted for aggregate ties between interconnected Settlement Areas. Missing tie values are assumed to be 0. The hourly residual determinant is expressed in terms of levelized MW. The formula for the hourly residual load determinant is shown below.

$$\text{RtResMtrHrlyQty}_{sa, h} = \left( \sum_{a} \sum_{ml} \{ \text{IF IsPsgiPsl} (ml) \text{ THEN 0 ELSE} \text{RtAdjMtrHrlyQty}_{sa, a, ml, h} \} + \text{RtSaNetActIchngHrlyQty}_{sa, h} + \sum_{i} \text{RtSELoss5minQty}_{sa, i} / 12 \right) * (-1)$$

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The amount is calculated as follows:

$$\text{RtEnergyHrlyAmt}_{a, s, h} = \sum_{i} \text{RtEnergy5minAmt}_{a, s, i}$$

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

$$\text{RtEnergyDlyAmt}_{a, s, d} = \sum_{h} \text{RtEnergyHrlyAmt}_{a, s, h}$$
(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{RtEnergyAoAmt}_{a, m, d} = \sum_i \text{RtEnergyDlyAmt}_{a, s, d}
\]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{RtEnergyMpAmt}_{m, d} = \sum_a \text{RtEnergyAoAmt}_{a, m, d}
\]

(1) For FERC Electric Quarterly Reporting (EQR) purposes, SPP calculates net Dispatch Interval sales volume in excess of DA Market amounts and associated prices and calculates net Dispatch Interval purchases when Real-Time sales volume less than DA Market sales volume and associated prices that are associated with this Charge Type for each Asset Owner as follows:

(a) \#EqrRtAssetEnergy5minQty_{a, s, i} =

\[
\text{Max} \left( 0, -1 \times \left[ (\text{RtBillMtr5minQty}_{a, s, i} - \text{DaClrdHrlyQty}_{a, s, h}) \right. \right.
\]

\[
- \sum_t \text{RtEnFinHrlyQty}_{a, s, t, h} \left. \right] / 12
\]

\[
+ \{ \text{IF } \#EqrDaAssetEnergyHrlyQty_{a, s, h} > 0 \text{ THEN }
\]

\[
\text{Min} \left( 0, -1 \times \left[ (\text{RtBillMtr5minQty}_{a, s, i} - \text{DaClrdHrlyQty}_{a, s, h}) \right. \right.
\]

\[
- \sum_t \text{RtEnFinHrlyQty}_{a, s, t, h} \left. \right] / 12 \} \}
\]

(b) IF \#EqrRtAssetEnergy5minQty_{a, s, i} < > 0 THEN

\[
\#EqrRtAssetEnergy5minPrc_{a, s, i} = \text{RtLmp5minPrc}_{s, i}
\]
The above variables are defined as follows:

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<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtEnergy5minAmt (_{a,s,i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Energy Amount per AO per Settlement Location per Dispatch Interval - The amount to AO (a) for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids at Settlement Location (s) for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtLmp5minPrc (_{s,i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time LMP - The RTBM LMP at Settlement Location (s) for Dispatch Interval (i).</td>
</tr>
<tr>
<td>DaClrdHrlyQty (_{a,s,h})</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>RtBillMtr5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The Dispatch Interval metered quantities for AO (a) Resources and load at Settlement Location (s) in Dispatch Interval (i) used by SPP for settlement purposes.</td>
</tr>
<tr>
<td>RtActMtr5minQty (_{a,ml,i})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Actual Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval metered quantity, in MWh, for AO (a)’s Resources and load directly submitted by the Market Participant.</td>
</tr>
<tr>
<td>RtActMtrHrlyQty (_{a,ml,h})</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Actual Meter Quantity per AO per Meter Data Submittal Location per Hour - The hourly metered quantity, in MWh, for AO (a)’s Resources and load directly submitted by the Market Participant.</td>
</tr>
<tr>
<td>RtMIBillMtr5minQty (_{a,ml,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval quantities adjusted to account for calibration Energy for AO (a) load at Meter Location (ml) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtCalMtr5minQty (_{a,ml,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Calibration Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval calibration quantities calculated by SPP for AO (a) at load at Meter Data Submittal Location (ml) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtCalMtrHrlyQty (_{a,ml,h})</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Calibration Meter Quantity per AO per Meter Settlement Location per Hour - The Dispatch Interval calibration Energy quantities calculated by SPP for AO (a) at load at Meter Data Submittal Location</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td><strong>RtLoadGrossUp5minQty</strong> [^{[MPRR77.8]}]  [^{[ML]}] [^{[ml]}]  [^{[i]}]  [^{[MW]}]</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Load Gross Up per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval load gross up associated with a Demand Response Reserve for AO [^{[a]}] at load Meter Data Submittal Location [^{[ml]}] associated with Settlement Location [^{[s]}] in Dispatch Interval [^{[i]}].</td>
</tr>
<tr>
<td><strong>RtSE5minQty</strong> [^{[a, ml, i]}]</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time State Estimator Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval State Estimator value for AO [^{[a]}] at Meter Data Submittal Location [^{[ml]}] in Dispatch Interval [^{[i]}].</td>
</tr>
<tr>
<td><strong>RtBaseLineHrlyQty</strong> [^{[a, ml(hrl), h]}]</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Base Line Load Quantity per AO per Demand Response Load Meter Data Submittal Location per Hour – The estimated consumption value associated with AO [^{[a]}] ’s Demand Response Load as submitted prior to Operating Hour [^{[h]}].</td>
</tr>
<tr>
<td><strong>RtSELoss5minQty</strong> [^{[sa, i]}]</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time State Estimator Losses per AO per Settlement Area per Dispatch Interval - The Dispatch Interval State Estimator total losses value for Settlement Area [^{[sa]}] in Dispatch Interval [^{[i]}].</td>
</tr>
<tr>
<td><strong>RtResMtrHrlyQty</strong> [^{[sa, h]}]</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Residual Load per Settlement Area per Hour - The hourly Residual Load for Settlement Area [^{[sa]}] in Hour [^{[h]}].</td>
</tr>
<tr>
<td><strong>IsPsgiPsgi (ml)</strong></td>
<td>None</td>
<td>None</td>
<td>A Logical operation of the Meter Data Submittal Location to determine if it is of type PSGI or PSLI – a Resource or load pseudo-tied into SPP, but not accounted for in the submittal of interchange of any Settlement Area.</td>
</tr>
<tr>
<td><strong>RtSaNetActIchngHrlyQty</strong> [^{[sa, h]}]</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Net Actual Interchange per Settlement Area per Hour - The sum of hourly actual interchange values submitted for Settlement Area [^{[sa]}] in Hour [^{[h]}].</td>
</tr>
<tr>
<td><strong>RtAdjMtr5minQty</strong> [^{[a, ml, i]}]</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Adjusted Actual Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval metered quantity, in MW, for AO [^{[a]}] ’s Resources and load calculated by SPP to account for load adjustments related to Demand Response Resources and to calculate a default value if <strong>RtActMtrHrlyQty</strong> [^{[a, ml, h]}] or <strong>RtActMtr5minQty</strong> [^{[a, ml, i]}] is not submitted.</td>
</tr>
<tr>
<td><strong>RtAdjMtrHrlyQty</strong> [^{[a, ml, h]}]</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Adjusted Actual Meter Quantity per AO per Meter Data Submittal Location per Hour - The hourly metered quantity, in MWh,</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>----------</td>
<td>---------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtEnFinHrlyQty $a, s, t, h$</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Asset Bilateral Settlement Schedule for Energy per AO per Settlement Location per Transaction per Hour - The amount specified by the buyer AO and seller AO in an RTBM Bilateral Settlement Schedule for Energy at Asset Settlement Location $s$, for transaction $t$, for the Hour. The buyer AO amount is a positive value and the seller AO amount is a negative value.</td>
</tr>
<tr>
<td>RtEnergyHrlyAmt $a, s, h$</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Energy Amount per AO per Settlement Location per Hour - The amount to AO $a$ for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids at Settlement Location $s$ for the Hour.</td>
</tr>
<tr>
<td>RtEnergyDlyAmt $a, s, d$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Energy Amount per AO per Settlement Location per Operating Day - The amount to AO $a$ for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids at Settlement Location $s$ for the Operating Day.</td>
</tr>
<tr>
<td>RtEnergyAoAmt $a, m, d$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Energy Amount per AO per Operating Day - The amount to AO $a$ associated with Market Participant $m$ for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids for the Operating Day.</td>
</tr>
<tr>
<td>RtEnergyMpAmt $m, d$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Energy Amount per MP per Operating Day - The amount to MP $m$ for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids for the Operating Day.</td>
</tr>
<tr>
<td>EqrRtAssetEnergy5minQty $a, s, i$</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Asset Energy Transactions per AO per Settlement Location per Dispatch Interval– AO $a$’s RTBM Energy sale at Resource Settlement Location $s$ in excess of the amount cleared Day-Ahead, net of Bilateral Settlement Schedules, in Dispatch Interval $i$ or AO $a$’s RTBM Energy purchase at Resource Settlement Location $s$ created when the actual Real-Time output is less than the amount cleared Day-Ahead, net of Financial Schedules, in Dispatch Interval $i$, for use by AO $a$ in reporting such sales/purchases to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>EqrRtAssetEnergy5minPrc $a, s, i$</td>
<td>$$/MWh$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Electric Quarterly Reporting net Asset Energy Transactions Prices per AO per Settlement Location per Dispatch Interval</em> – AO $a$’s prices associated with non-zero EqrRtAssetEnergy5minQty $a, s, i$ quantities in Dispatch Interval $i$ for use by AO $a$ in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$i$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$s$</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Bilateral Settlement Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>ml(drr)</td>
<td>none</td>
<td>none</td>
<td>A Demand Response Resource Meter Data Submittal Location.</td>
</tr>
<tr>
<td>ml(drl)</td>
<td>none</td>
<td>none</td>
<td>A Demand Response Load Meter Data Submittal Location.</td>
</tr>
<tr>
<td>sa</td>
<td>none</td>
<td>none</td>
<td>A Settlement Area.</td>
</tr>
<tr>
<td>ml</td>
<td>none</td>
<td>none</td>
<td>A Meter Data Submittal Location.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.20 Real-Time Over-Collected Losses Distribution Amount

(1) The Marginal Losses Component of the RTBM LMP that results from the economic market solution which considers the cost of marginal losses, congestion costs and incremental Energy costs creates an over collection (or under collection as a result of the Real-Time deviation accounting) related to payment for losses (“RTBM Over-Collected Losses”) that must be accounted for. A RTBM credit or charge is calculated for each hour at each Settlement Location for which an Asset Owner has a net RTBM Energy withdrawal that contributed positively to the over collection or under collection or paid a charge for Real-Time Pseudo-Tie Losses at the Settlement Location of the Sink of the Pseudo-Tie path. Each Asset Owner’s contribution to the RTBM Over-Collected Losses is calculated based upon a Loss Pool that is dynamically defined by the Asset Owner’s transactional activity. A loss rebate factor is calculated for each Asset Owner and withdrawal Settlement Location as the sum of i) the difference between the Marginal Loss Component at a withdrawal Settlement Location in the Asset Owner’s Loss Pool and the injection weighted average Marginal Loss Component for the Asset Owner’s Loss Pool, multiplied by that Asset Owner’s share of the net withdrawal (calculated excluding cleared DA Market Virtual Bids and cleared DA Market Virtual Offers) at that Settlement Location and ii) the sum of charges for Real-Time Pseudo-Tie Losses at the Settlement Location of the Sink of the Pseudo-Tie path. The injection weighted average MLC for the Asset Owner’s Loss Pool is calculated assuming that injection in the Loss Pool first serves withdrawal in the Loss Pool and then goes to meet the withdrawal in Loss Pools which do not have sufficient injection to meet all withdrawal. The loss rebate factor (positive value only, negative values are ignored) is a measure of the payment for losses on a marginal basis at each Settlement Location. The loss rebate factors are then normalized to allocate a pro-rata portion of the total over collection or under collection in the hour to Asset Owners by Settlement Location. The amount is calculated as follows:

\[
\text{#RtOclDistHrlyAmt}_{a, s, lp, h} = \text{RtNormLossRbtHrlyFct}_{a, s, lp, h} \times \text{RtIncrOclHrlyAmt}_{h} \times (-1)
\]

Where,

\[
\text{(a) } \text{RtIncrOclHrlyAmt}_{h} = \sum \text{RtIncrOcl5minAmt}_{i}
\]

\[
\text{(a.1) } \text{#RtIncrOcl5minAmt}_{i} = \]

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\[
\sum_i \sum_j \sum_s \left( \sum_t \left( \sum_k \sin \left( \frac{\text{RtPseudoTieLoss5minAmt}_{a, \text{source}, \text{sink}, i}}{\text{source}} \right) \right) \right) - \sum_i \sum_s \sum_j \sum_t \text{DaImpExp5minQty}_{a, s, lp, i, t} - \sum_i \sum_s \sum_j \sum_t \text{DaClrdVHrlyQty}_{a, s, lp, h, t} + \frac{\sum_i \sum_s \sum_j \sum_t \text{RtImpExp5minQty}_{a, s, lp, i, t} - \sum_i \sum_s \sum_j \sum_t \text{DaImpExp5minQty}_{a, s, lp, i, t}}{12} + \text{RtNetInadvertentSpp5minAmt}_i + \text{RtPseudoTieLossSpp5minAmt}_i \]

\[(a.2) \quad \text{RtPseudoTieLossSpp5minAmt}_i = \]

\[
\sum_a \sum_s \sum_{\text{source}} \sum_{\text{sink}} \text{RtPseudoTieLoss5minAmt}_{a, \text{source}, \text{sink}, i} \]

(b) \quad \text{IF } \text{RtLossRbtSppHrlyFct}_h = 0 \\
\quad \text{THEN} \\
\quad \text{RtNormLossRbtHrlyFct}_{a, s, lp, h} = 0 \\
\quad \text{ELSE} \\
\quad \#\text{RtNormLossRbtHrlyFct}_{a, s, lp, h} = \\
\quad \text{Max} (0, \text{RtLossRbtHrlyFct}_{a, s, lp, h}) / \text{RtLossRbtSppHrlyFct}_h \\

(b.1) \quad \text{RtLossRbtSppHrlyFct}_h = \sum_a \sum_s \sum_{\text{source}} \sum_{\text{sink}} \text{Max} (0, \text{RtLossRbtHrlyFct}_{a, s, lp, h}) \\

(c) \quad \text{RtLossRbtHrlyFct}_{a, s, lp, h} = \sum_i \text{Max} (0, \text{RtLossRbt5minFct}_{a, s, lp, i}) \\

(c.1) \quad \#\text{RtLossRbt5minFct}_{a, s, lp, i} = \{ \left[ \text{RtLpIntSupply5minFct}_{lp, i} \right. \right. \\
\left. \left. \quad \times (\text{RtMlc5minPrc}_{s, i} - \text{RtLpIwaMlc5minPrc}_{lp, i}) \right) \right. \\
\left. \left. \quad + (1 - \text{RtLpIntSupply5minFct}_{lp, i}) \right) \right. \\
\left. \left. \quad \times (\text{RtMlc5minPrc}_{s, i} - \text{RtSppIwaMlc5minPrc}_{i}) \right] \}
* RtLpNetWdr5minQty \( a, s, lp, i \) \}

\[ \sum_{\text{source}} \text{RtPseudoTieLoss5minAmt} \quad \text{source, sink} (s) \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$RtPseudoTieLossSpp5minAmt_{i}$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time SPP Total Pseudo-Tie Losses Amount per Dispatch Interval - The total amount for losses on Pseudo-Ties in Dispatch Interval $i$.</td>
</tr>
<tr>
<td>$RtPseudoTieLoss5minAmt_{a, source, sink, (s), i}$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Pseudo-Tie Losses Amount per Asset Owner per source-sink path per Dispatch Interval - The value described under 4.5.9.27 for AO $a$ on path source to sink in Dispatch Interval $i$. For the purpose of its inclusion in the calculation of the Loss Rebate Factor the sink ($s$) notation is an indication that value is collected at the sink Settlement Location.</td>
</tr>
</tbody>
</table>
4.5.9.2 Real-Time Pseudo-Tie Congestion Amount

(1) An RTBM charge or credit will be calculated for each Resource or load, internal to the SPP footprint, that has pseudo-tied out of the SPP Balancing Authority for each Dispatch Interval of the Operating Day. The amount is calculated as follows:

\[
\#RtPseudoTieCong5minAmt_{a, source, sink, i} = \frac{RtPseudoTie5minQty_{a, source, sink, i} \times (RtMcc5minPrc_{sink, i} - RtMcc5minPrc_{source, i})}{12}
\] (6)

(6) For each Asset Owner, an hourly amount is calculated on each source to sink path. The amount is calculated as follows:

\[
RtPseudoTieCongHrlyAmt_{a, source, sink, h} = \sum_i RtPseudoTieCong5minAmt_{a, source, sink, i}
\] (7)

(7) For each Asset Owner, a daily amount is calculated on each source to sink path. The amount is calculated as follows:

\[
RtPseudoTieCongDlyAmt_{a, source, sink, d} = \sum_h RtPseudoTieCongHrlyAmt_{a, source, sink, h}
\] (8)

(8) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\[
RtPseudoTieCongAoAmt_{a, m, d} = \sum_{source} \sum_{sink} \sum_i RtPseudoTieCongDlyAmt_{a, source, sink, d}
\] (9)

(9) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
RtPseudoTieCongMpAmt_{m, d} = \sum_a RtPseudoTieCongAoAmt_{a, m, d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtPseudoTieCong5minAmt&lt;sub&gt;a, source, sink&lt;/sub&gt;,&lt;sub&gt;i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Pseudo-Tie Congestion Amount per Asset Owner per source-sink path per Dispatch Interval - The amount for Pseudo-Tie congestion on path source to sink for AO a in Dispatch Interval i.</td>
</tr>
<tr>
<td>RtPseudoTie5minQty&lt;sub&gt;a, source, sink&lt;/sub&gt;,&lt;sub&gt;i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Pseudo-Tie Quantity per Asset Owner per source-sink path per Dispatch Interval - The telemetered Pseudo-Tie flow on path source to sink for AO a in Dispatch Interval i.</td>
</tr>
<tr>
<td>RtMcc5minPre&lt;sub&gt;source&lt;/sub&gt;,&lt;sub&gt;i&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Marginal Congestion Component of Real-Time LMP – The Marginal Congestion Component of the Real-Time LMP at the Settlement Location of the source point specified on the Pseudo-Tie path for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtMcc5minPre&lt;sub&gt;sink&lt;/sub&gt;,&lt;sub&gt;i&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Marginal Congestion Component of Real-Time LMP – The Marginal Congestion Component of the Real-Time LMP at the Settlement Location of the sink point specified on the Pseudo-Tie path for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtPseudoTieCongHrlyAmt&lt;sub&gt;a, source, sink&lt;/sub&gt;,&lt;sub&gt;h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Pseudo-Tie Congestion Amount per Asset Owner per source-sink path per Hour - The amount for Pseudo-Tie congestion on path source to sink for AO a in Hour h.</td>
</tr>
<tr>
<td>RtPseudoTieCongDlyAmt&lt;sub&gt;a, source, sink&lt;/sub&gt;,&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Pseudo-Tie Congestion Amount per Asset Owner per source-sink path per Operating Day - The amount for Pseudo-Tie congestion on path source to sink for AO a for the Operating Day.</td>
</tr>
<tr>
<td>RtPseudoTieCongAoAmt&lt;sub&gt;a, m&lt;/sub&gt;,&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Pseudo-Tie Congestion Amount per Asset Owner per Operating Day - The amount for Pseudo-Tie congestion on all paths for AO a associated with Market Participant m for the Operating Day.</td>
</tr>
<tr>
<td>RtPseudoTieCongMpAmt&lt;sub&gt;m&lt;/sub&gt;,&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Pseudo-Tie Congestion Amount per Market Participant per Operating Day - The amount for Pseudo-Tie congestion on all paths for MP m for the Operating Day.</td>
</tr>
</tbody>
</table>

A

Source

none

none

An Asset Owner.

The Settlement Location identified as the source point of a Pseudo-Tie.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sink</td>
<td>none</td>
<td>none</td>
<td>The Settlement Location identified as the sink point of a Pseudo-Tie.</td>
</tr>
<tr>
<td>$H$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$I$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$D$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$M$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.2 Real-Time Pseudo-Tie Losses Amount

(1) An RTBM charge or credit will be calculated for each Resource or load, internal to the SPP footprint, that has pseudo-tied out of the SPP Balancing Authority for each Dispatch Interval of the Operating Day. The amount is calculated as follows:

\[
\#\text{RtPseudoTieLoss5minAmt}_{a, \text{source, sink}, i} = \text{RtPseudoTie5minQty}_{a, \text{source, sink}, i} \times (\text{RtMlc5minPrc}_{\text{sink}, i} - \text{RtMlc5minPrc}_{\text{source}, i}) / 12
\]

(2) For each Asset Owner, an hourly amount is calculated on each source to sink path. The amount is calculated as follows:

\[
\text{RtPseudoTieLossHrlyAmt}_{a, \text{source, sink}, h} = \sum_i \text{RtPseudoTieLoss5minAmt}_{a, \text{source, sink}, i}
\]

(3) For each Asset Owner, a daily amount is calculated on each source to sink path. The amount is calculated as follows:

\[
\text{RtPseudoTieLossDlyAmt}_{a, \text{source, sink}, d} = \sum_h \text{RtPseudoTieLossHrlyAmt}_{a, \text{source, sink}, h}
\]

(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{RtPseudoTieLossAoAmt}_{a, m, d} = \sum_{\text{source}} \sum_{\text{sink}} \text{RtPseudoTieLossDlyAmt}_{a, \text{source, sink}, d}
\]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{RtPseudoTieLossMpAmt}_{m, d} = \sum_a \text{RtPseudoTieLossAoAmt}_{a, m, d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\text{RtPseudoTieLoss5minAmt}_{a, \text{source}, \text{sink}, i}$</td>
<td>$\text{$}$</td>
<td>Dispatch Interval</td>
<td>Real-Time Pseudo-Tie Losses Amount per Asset Owner per source-sink path per Dispatch Interval - The amount for Pseudo-Tie losses on path source to sink for AO $a$ in Dispatch Interval $i$.</td>
</tr>
<tr>
<td>$\text{RtPseudoTie5minQty}_{a, \text{source}, \text{sink}, i}$</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Pseudo-Tie Quantity per Asset Owner per source-sink path per Dispatch Interval - The telemetered Pseudo-Tie flow on path source to sink for AO $a$ in Dispatch Interval $i$.</td>
</tr>
<tr>
<td>$\text{RtMlc5minPrc}_{\text{source}, i}$</td>
<td>$\text{$/MWh}$</td>
<td>Dispatch Interval</td>
<td>Real-Time Marginal Losses Component of Real-Time LMP – The Marginal Losses Component of the Real-Time LMP at the Settlement Location of the source point specified on the Pseudo-Tie path for Dispatch Interval $i$.</td>
</tr>
<tr>
<td>$\text{RtMlc5minPrc}_{\text{sink}, i}$</td>
<td>$\text{$/MWh}$</td>
<td>Dispatch Interval</td>
<td>Real-Time Marginal Losses of Real-Time LMP – The Marginal Losses Component of the Real-Time LMP at the Settlement Location of the sink point specified on the Pseudo-Tie path for Dispatch Interval $i$.</td>
</tr>
<tr>
<td>$\text{RtPseudoTieLossHrlyAmt}_{a, \text{source}, \text{sink}, h}$</td>
<td>$\text{$}$</td>
<td>Hour</td>
<td>Real-Time Pseudo-Tie Losses Amount per Asset Owner per source-sink path per Hour - The amount for Pseudo-Tie losses on path source to sink for AO $a$ in Hour $h$.</td>
</tr>
<tr>
<td>$\text{RtPseudoTieLossDivAmt}_{a, \text{source}, \text{sink}, d}$</td>
<td>$\text{$}$</td>
<td>Operating Day</td>
<td>Real-Time Pseudo-Tie Losses Amount per Asset Owner per source-sink path per Operating Day - The amount for Pseudo-Tie losses on path source to sink for AO $a$ for the Operating Day.</td>
</tr>
<tr>
<td>$\text{RtPseudoTieLossAoAmt}_{a, \text{m}, d}$</td>
<td>$\text{$}$</td>
<td>Operating Day</td>
<td>Real-Time Pseudo-Tie Losses Amount per Asset Owner per Operating Day - The amount for Pseudo-Tie losses on all paths for AO $a$ associated with Market Participant $m$ for the Operating Day.</td>
</tr>
<tr>
<td>$\text{RtPseudoTieLossMpAmt}_{\text{m}, d}$</td>
<td>$\text{$}$</td>
<td>Operating Day</td>
<td>Real-Time Pseudo-Tie Losses Amount per Asset Owner per Operating Day - The amount for Pseudo-Tie losses on all paths for MP $m$ for the Operating Day.</td>
</tr>
</tbody>
</table>

$A$  

none  

none  

An Asset Owner.

$Source$  

none  

none  

The Settlement Location identified as the source point of a Pseudo-Tie,
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sink</td>
<td>none</td>
<td>none</td>
<td>The Settlement Location identified as the sink point of a Pseudo-Tie.</td>
</tr>
<tr>
<td>H</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>I</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>D</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>M</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.12 Revenue Neutrality Uplift Distribution Amount

(b.4) \[ \#RtCongestionSppAmt_{spp, d} = \]

\[
\frac{\sum \sum \sum ( ( RtBillMtr5minQty_{a, s, i} - DaClrdHrlyQty_{a, s, h} ) + \sum (RtImpExp5MinQty_{a, s, i, t} - DaImpExp5MinQty_{a, s, i, t}) - \sum DaClrdVHrlyQty_{a, s, h, t} ) * RtMcc5minPrc_{a, s, i} )}{12}
\]

(b.4.1) \[ RtPseudoTieCongSppAmt_{d} = \sum RtPseudoTieCongMpAmt_{m, d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$RtPseudoTieCongSppAmt_{d}$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time SPP Total Pseudo-Tie Congestion Amount per Dispatch Interval - The total amount for congestion on Pseudo-Ties for the Operating Day.</td>
</tr>
<tr>
<td>$RtPseudoTieCongMpAmt_{m,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Pseudo-Tie Congestion Amount per Market Participant per Operating Day - The value described under 4.5.9 for MP $m$ for the Operating Day.</td>
</tr>
</tbody>
</table>
6.1.10 Resources External to the SPP BA

6.1.10.1 External Dynamic Resources
A Market Participant registers an EDR for the purposes of accounting for importing of Operating Reserve that is sourced external to the SPP BA. An External Dynamic Resource that is modeled in the Eastern Interconnection may either represent a single Resource or a fleet of Resources and is not subject to Energy dispatch, only clearing and deployment of the Operating Reserve products that the EDR is qualified to provide, except that an associated Dynamic Schedule for Energy may be used for the purposes of providing Regulation-Down which must be specified at registration. An EDR that is associated with a DC tie-line is modeled as a single Resource and may be available for Energy dispatch and/or Operating Reserve clearing which must be specified at registration. See Section 4.2.2.5.7 for specific modeling details.

6.1.10.2 Pseudo-Tied Resources External to the SPP BA Pseudo-Tying In
Market Participants with Resources external to the SPP BA, other than External Dynamic Resources, wishing to participate in the SPP Integrated Marketplace with those Resources must pseudo-tie those Resources into the SPP Balancing Authority (BA) utilizing the SPP OATT Attachment AO or equivalent agreement approved by SPP.

(a) In addition to the responsibilities outlined in the Attachment AO agreement, the Market Participant representing the Resource will be responsible for registering and performing all responsibilities that are required of any other Resource in the SPP Integrated Marketplace.

(b) The Market Participant representing the Resource must be the Meter Agent or contract with Designating a Meter Agent that will be responsible for submittal of settlement meter data as described under Section 2.1.3 of Appendix D.

(c) Firm transmission service from the Resource to the SPP border is required.

(a)(d) Market Participants may remove or add pseudo-tied in Resources in accordance with the timelines described under Section 6.4.

6.1.10.3 Resources Internal to the SPP BA Pseudo-Tying Out
Market Participants with Resources interconnected to the SPP transmission system not wishing to participate in the SPP Integrated Marketplace with those Resources have the option to pseudo-tie those Resources out of the SPP Balancing Authority (BA) utilizing the SPP OATT Attachment AO or equivalent agreement approved by SPP.

(a) The Market Participant representing the Resource must be registered in the SPP Integrated Marketplace for the purposes of accounting for congestion and loss costs incurred within the SPP BA resulting from the Pseudo-Tied Resource output.
(b) The Market Participant will not be allowed to offer the Resource in the DA Market, RUC, or RTBM.

(c) Firm Transmission service is required from the Resource to the SPP border.

(d) Market Participants may remove or add pseudo-tied OATT Resources in accordance with the timeline described under Section 6.4.

6.11 Operating Reserve Certification

Asset Owners of registered Resource must meet the following certification requirements in order to be eligible to submit Operating Reserve Offers for use in the SPP Integrated Marketplace.

6.2.5 Block Demand Response Load Settlement Location

As part of the registration of a Block Demand Response Resource, the Asset Owner must also identify a corresponding load Settlement Location in which the associated Demand Response Load resides. The Block Demand Response Load is used by SPP for settlements.

6.2.6 Loads External to the SPP BA Pseudo-Tying In

Market Participants with Load external to the SPP BA wishing to participate in the SPP Integrated Marketplace must pseudo-tie that Load into the SPP Balancing Authority (BA) utilizing the SPP OATT Attachment AO or equivalent agreement approved by SPP.

(a) In addition to the responsibilities outlined in the Attachment AO agreement, the Market Participant representing the Load will be responsible for registering and performing all responsibilities that are required of any other Load in the SPP Integrated Marketplace.

(b) The Market Participant representing the Load must be the Meter Agent or contract with a Meter Agent that will be responsible for submission of settlement meter data as described under section 7.1.3 of Appendix D.

(c) Firm transmission service from the Load to the SPP border is required.

(d) Market Participants may remove or add pseudo-tied in Load in accordance with the timeline described under Section 6.4.

6.2.7 Loads Internal to the SPP BA Pseudo-Tying Out

Market Participants representing Load interconnected to the SPP transmission system wishing not to participate with that Load in the SPP Integrated Marketplace have the option to pseudo-tie that Load out of the SPP Balancing Authority (BA) utilizing the SPP OATT Attachment AO or equivalent agreement approved by SPP.
(a) The Market Participant representing the Load will be responsible for registering in the SPP Integrated Marketplace for the purposes of accounting for congestion and loss costs incurred within the SPP BA resulting from the pseudo-Tied Load consumption.

(b) The Market Participant representing the Load will not be permitted to Demand Bids in the Day-Ahead Market associated with load loss.

(c) Firm Transmission from the Load to the SPP border is required.

(d) Market Participants may remove or add pseudo-Tied Load in accordance with the timelines described under Section 6.4.

Appendix D - Settlement Metering Data Management Protocols

7. Settlement Meter Data Types

There are three basic types of interval settlement data required for the SPP Integrated Marketplace.

Meter Data Submittal Locations:

1. Resources (generation)
2. Loads
3. Settlement Area Interchange: (Hourly metered interchange between Settlement Areas, and between Settlement Areas and external Balancing Authorities)

7.2.3 Residual Load

Residual Load in a Settlement Area is the sum of the hourly metered interchange between Settlement Areas, plus the sum of all Resource Meter Data Submittal Locations less all other load Meter Data Submittal Location as reported separately under Section 7.2.2 for that Settlement Area. Residual Load is submitted by the Meter Agent representing the Market Participant responsible for Residual Load in the same manner as other Meter Data Submittal Locations for loads. SPP adjusts the submitted Residual Load for transmission system losses as described under Section 4.5.9.1.

7.3 Hourly Metered Interchange

Each Meter Agent that is responsible for the calculation of total Settlement Area load shall report hourly metered interchange between each Settlement Area and each external Balancing Authority with which its Settlement Area is interconnected. Meter data must be submitted in hourly intervals according to the sign convention. Hourly metered
interchange is reported based on the Settlement Area’s prospective. See Section 6: Data Format for sign convention. The hourly metered interchange is needed for the calibration function of settlements (See Section 4.5.9.1 for a description of the calibration calculation).

7.3.1 Substitution for Missing Data

In the event that a Meter Agent fails to submit Settlement Area hourly metered interchange data, SPP will initially use the value calculated by the State Estimator until the actual value is submitted prior to final settlement.

| Proposed Tariff Language Revision |

Attachment AE

2.2 Application and Asset Registration

(1) Applications for a Market Participant to provide services in the Integrated Marketplace must be submitted to the Transmission Provider prior to the expected date of participation consistent with Section 6.4 of the Market Protocols. Applications must conform to the procedures specified in the Market Protocols and may be rejected if not complete. New Market Participants will follow the timeframe as specified in Section 6.4 of the Market Protocols in addition to the detailed model update timing requirements in Appendix E of the Market Protocols.

(2) As part of the application process, Market Participants must register all Resources and load, including applicable load associated with Grandfathered Agreements (“GFAs”),
Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols. *As part of Resource registration, Market Participants must specify whether settlement meter data will be submitted on a gross basis or net basis, where gross meter data does not include reductions for auxiliary load and net meter data is gross meter data reduced by auxiliary load.* Both Non-Conforming Load and Demand Response Load may only be associated with a single Price Node except that Non-Conforming Load and Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes. Non-participating embedded load and/or generation must either: (i) register its load and/or generation in the Integrated Marketplace; or (ii) transfer its load and/or generation to an external Balancing Authority.

(3) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Data Submittal Locations associated with their load assets. *Market Participants may not aggregate multiple Resource Meter Data Submittal Locations into a single Resource Settlement Location unless the Resources are at the same physical and electrically equivalent injection point to the Transmission System.*

(4) In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants wishing to model each participant’s share of a Jointly Owned Unit as a separate Resource must choose one of the two options described below and provide the specified additional information. A Resource registered as a combined cycle Resource may not register as a Jointly Owned Unit.

(a) Individual Resource Option

Under the individual Resource option, each participant’s share is modeled as a separate Resource for the purposes of commitment and dispatch and each Resource may be committed independent of the other Resource shares. In order to qualify for this option, each Market Participant must register its share and certify that it is greater than or equal to the minimum physical capacity operating limit of the physical Jointly Owned Unit.

The operating owner’s Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:
- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit; and
- Maximum physical ten (10) minute response from an off-line state.

(b) Combined Resource Option

Under the combined Resource option each participant’s share is modeled and must be registered as a separate Resource. Under this option, the commitment decision is made assuming that all Resource shares must be committed or none at all. Once committed, each share is dispatched independently. This option must be selected if the eligibility criteria stated under the individual Resource option cannot be met.

The operating owner’s Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit;
- Maximum physical ten (10) minute response from an off-line state; and
- Participant share percentage by Market Participant.

(5) Market Participants may modify their registered assets in accordance with the asset registration procedures specified in the Market Protocols.

(6) All loads and all Resources, excluding Behind-The-Meter Generation less than 10 Megawatts (“MWs”), must register. Failure or refusal to register a Resource will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in the Energy and Operating Reserve Markets or subject the Qualifying Facility to any charges or payments related to the Energy and Operating Reserve Markets.
(7) A Market Participant wishing to Offer an External Resource in the Energy and Operating Reserve Markets will utilize an External Resource Pseudo-Tie in accordance with Attachment AO. In addition to the responsibilities outlined in Attachment AO, the Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in the Energy and Operating Reserve Markets.

(8) A Market Participant wishing to offer Demand Response Load as a Demand Response Resource in the Energy and Operating Reserve Markets must include in its application and registration a certification that participation in the Energy and Operating Reserve Markets by its Demand Response Resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Consistent with Section 2.8 of this Attachment, an aggregator of retail customers wishing to offer Demand Response Load in the form of a Demand Response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year. Demand Response Resources must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

(9) An aggregator of retail customers offering Demand Response Load of one or more end-use retail customers as a Demand Response Resource in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants as well as certification consistent with Section 2.8 of this Attachment.
(10) A wind-powered Variable Energy Resource (1) with an interconnection agreement executed after May 21, 2011 or (2) an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation on or after October, 15, 2012 must register as a Dispatchable Variable Energy Resource. A wind-powered Variable Energy Resource with an interconnection agreement executed on or prior to May 21, 2011 may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider. Variable Energy Resources with fuel sources other than wind may optionally register as a Dispatchable Variable Energy Resource. Otherwise, Variable Energy Resources must register as Non-Dispatchable Variable Energy Resources. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

(11) A Market Participant that is selling firm power to the load asset under a bilateral contract may, with the agreement of the buyer, register all or a portion of the buyer's load as its load asset. For purposes of this Section 2.2(11) of this Attachment AE, the sale of firm power shall refer to power sales deliverable with firm transmission service, where the capacity and energy is supplied under standards of reliability and availability equivalent to supply of native load customers with the supplier assuming the obligation to provide both capacity and energy.

(12) A Transmission Owner providing firm transmission service under a GFA eligible for GFA Carve Out must request removal of congestion and marginal loss charges and designate the GFA Responsible Entity within the timeframe set forth in Section 2.2 (1) of Attachment AE.

(13) A GFA Responsible Entity shall provide to the Transmission Provider the information necessary to administer the GFA Carve Out. The required information shall include the following:

(a) Resource Settlement Location;
(b) Load Settlement Location;
(c) The maximum MW capacity contracted under the GFA Carve Out;
(d) The identification of the GFA in Attachment W; and
(e) Any other information reasonably required by the Transmission Provider.
(104) Market Participants with assets interconnected to the Transmission System that are not participating in the Energy and Operating Reserve Markets must pseudo-tie the Resource or load out of the SPP Balancing Authority Area in accordance with Attachment AO. Such assets shall continue to be registered in the Integrated Marketplace for the purposes of accounting for congestion and loss charges between the Resource Price Node and the applicable External Interface Settlement Location as described under Sections 8.6.19 and 8.6.20 of this Attachment AE.

(a) To the extent that the SPP Balancing Authority or associated external Balancing Authority can no longer maintain the Resource pseudo-tie for reliability reasons, the Market Participant representing the pseudo-tied Resource must immediately reduce the output of the pseudo-tied resource to the available pseudo-tie capability after receiving notification from the affected Balancing Authority of the reduced capability. A Market Participant shall not generate any energy in excess of the available pseudo-tie capability after receiving such notification and shall not be compensated in the Energy and Operating Reserve Markets settlement for any energy generated in excess of the available pseudo-tie capability.

4.3 Bid Submittal

(1) Beginning seven (7) days prior to the Operating Day, Market Participants may submit Demand Bids and Virtual Energy Bids for the purchase of Energy in the Day-Ahead Market.

(2) Beginning seven (7) days prior to the Operating Day, Market Participants may submit Export Interchange Transaction Bids for the purchase of Energy in the Day-Ahead Market or RTBM.

(3) Submitted Bids do not roll forward hour to hour.

(4) Demand Bids may only be submitted at load Settlement Locations.

(5) Export Interchange Transaction Bids may only be submitted at External Interface Settlement Locations.

(6) Virtual Energy Bids may be submitted at any Settlement Location.

(7) Bid submittal associated with a load pseudo-tied out of the SPP Balancing Authority is not permitted.
(1) Only Market Participants with registered physical load assets may submit Demand Bids for use in the Day-Ahead Market.

(2) A Market Participant can submit Demand Bids only at Settlement Locations where its physical load assets are registered.

(3) **A Market Participant is not permitted to submit a Demand Bid for a load asset pseudo-tied out of the SPP Balancing Authority.**

(3) A fixed Demand Bid is a specified MW that will be cleared in the Day-Ahead Market regardless of the price at the load Settlement Location based on the start and stop time submitted for the applicable Operating Day.

(4) A price sensitive Demand Bid is specified as a Demand Bid Curve. A price sensitive Demand Bid will clear only if the price at the load Settlement Location is less than or equal to the specified Demand Bid Curve price within the specified start and stop time submitted for the applicable Operating Day with the highest Megawatt quantity submitted in the Demand Bid Curve representing the maximum Megawatt amount that can be cleared.

### 8.6.16 Real-Time Over-Collected Losses Distribution Amount

The MLC of the RTBM LMP creates an over collection (or under collection as a result of the Real-Time deviation accounting) related to the payment for losses (“RTBM over-collected losses”) that must be accounted for. An RTBM payment or charge is calculated for each hour at each Settlement Location for which an Asset Owner has a net RTBM Energy withdrawal, where such withdrawal does not include Energy associated with cleared Day-Ahead Market Virtual Energy Bids and Virtual Energy Offers, which contributed positively to the RTBM over-collected losses or were charged for Real-Time pseudo-tie losses at the Settlement Location of the Sink of the pseudo-tie path for use of the SPP Transmission system as follows:

(1) Each Asset Owner’s calculated contribution to the RTBM over-collected losses is calculated based upon a Loss Pool that is defined on an hourly basis by the Asset Owner’s transactional activity where such transactional activity shall include: actual Resource Energy, actual load consumption, RTBM Import Interchange Transactions, RTBM Export Interchange Transactions, Bilateral Settlement Schedules, cleared Day-

(2) A loss rebate factor is calculated for each Asset Owner at each withdrawal Settlement Location in a Loss Pool as the sum of i) the difference between the Real-Time MLC at a withdrawal Settlement Location in the Loss Pool and the injection weighted average Real-Time MLC for the Loss Pool, multiplied by the Asset Owner’s withdrawal quantity at that withdrawal Settlement Location and ii) the sum of charges for Real-Time pseudo-tie losses at the Settlement Location or the sum of the pseudo-tie losses.

(a) An Asset Owners withdrawal quantity at a Settlement Location is equal to that Asset Owners pro-rata share of the total withdrawal at that Settlement Location.

(b) The total withdrawal quantity at a Settlement Location is calculated as the positive value of the sum of: (i) the difference between actual Resource outputs and cleared Day-Ahead Market Resource Offers; (ii) the difference between actual load consumption and cleared Day-Ahead Market Demand Bids; (iii) the difference between RTBM scheduled Import Interchange Transactions and Day-Ahead Market cleared Import Interchange Transaction Offers; (iv) the difference between RTBM scheduled Export Interchange Transactions and Day-Ahead Market cleared Export Interchange Transaction Bids; (v) cleared Day-Ahead Market Virtual Energy Bids multiplied by (-1); and (vi) cleared Day-Ahead Market Virtual Energy Offers multiplied by (-1), at that Settlement Location.

(c) An Asset Owner’s pro-rata share of the total withdrawal quantity at that Settlement Location is equal to the value calculated in (b) above multiplied by: (A) the positive value of the sum of that Asset Owner’s: (i) the difference between actual Resource outputs and cleared Day-Ahead Market Resource Offers; (ii) the difference between actual load consumption and cleared Day-Ahead Market Demand Bids; (iii) the difference between RTBM scheduled Import Interchange Transactions and Day-Ahead Market cleared Import Interchange Transaction Offers; (iv) the difference between RTBM scheduled Export Interchange Transactions and Day-Ahead Market cleared Export Interchange Transaction Bids; and (v) Bilateral Settlement Schedules, at that Settlement Location, divided by; (B) the sum of Asset Owners’ values calculated in (A) above at that Settlement Location.
(3) The injection weighted average Real-Time MLC for a Loss Pool is calculated assuming that net RTBM injection in a Loss Pool first serves net RTBM withdrawals in the Loss Pool and then goes to meet the net RTBM withdrawal in Loss Pools that do not have sufficient Net RTBM injections to meet all net RTBM withdrawals.

(4) The RTBM over-collected losses are allocated to Asset Owners on a pro-rata basis using the positive loss rebate factors in the hour for each load Settlement Location. Only positive loss rebate factors apply and negative values are ignored.

(5) A Real-Time over-collected losses distribution amount is calculated as follows:

Real-Time Over-Collected Losses Distribution Amount =

\[
[(\text{Real-Time Unitized Loss Rebate Factor}) \times (\text{Real-Time Over-Collected Losses Amount})] \times (-1)
\]

(a) The Real-Time Over-Collected Losses Amount in an hour is equal to the sum for all Settlement Locations of \([(\text{Day-Ahead LMP} - \text{Day-Ahead MCC})] \times \text{the difference between actual Energy and Day-Ahead Market cleared Energy MW at each Settlement Location plus the sum of the losses for all Resources or loads that are pseudo-tied out of the SPP Balancing Authority.}

(b) Real-Time Unitized Loss Rebate Factor is the factor calculated as described in (4) above.

8.6.19 Real-Time Pseudo-Tie Congestion Amount

A RTBM charge or credit will be calculated for each Resource or load that is pseudo-tied out of the SPP Balancing Authority for each Dispatch Interval of the Operating Day. The amount is calculated as follows:

Real-Time Pseudo-Tie Congestion Amount =

(Real-Time Pseudo-Tie Quantity)

\*[((\text{Real-Time MCC at the sink}) - (\text{Real-Time MCC at the source}))]

(1) Real-Time Pseudo-Tie Quantity is the telemetered value of the Resource or load that is pseudo-tied out of the SPP Balancing Authority.

(2) Real-Time MCC is as defined under Section 1 of this Attachment AE.
8.6.20 Real-Time Pseudo-Tie Losses Amount

A RTBM charge or credit will be calculated for each Resource or load that is pseudo-tied out of the SPP Balancing Authority for each Dispatch Interval of the Operating Day. The amount is calculated as follows:

Real-Time Pseudo-Tie Losses Amount =

(Real-Time Pseudo-Tie Quantity) * [(Real-Time MLC at the sink) - (Real-Time MLC at the source)]

(1) Real-Time Pseudo-Tie Quantity is the telemetered value of the Resource or load that is pseudo-tied out of the SPP Balancing Authority.

(2) Real-Time MLC is as defined under Section 1 of this Attachment AE.
ATTACHMENT AO
AGREEMENT ESTABLISHING EXTERNAL GENERATION NON-PHYSICAL A PSEUDO-TIE ELECTRICAL INTERCONNECTION POINT

This Agreement Establishing External Generation Non-Physical a Pseudo-Tie Electrical Interconnection Point (including its exhibits, this “Agreement”) is entered into this ____ day of __________ 20____ by and among ____________(Source—External Balancing Authority), ____________(Market Participant), and the Southwest Power Pool, Inc. (“SPP”). Source—External Balancing Authority, Market Participant and SPP are hereinafter referred to individually as a “Party” and collectively as the “Parties.”

WHEREAS, in order to facilitate the foregoing, the Parties desire to establish a new non-physical pseudo-tie electrical interconnection point between the SPP External Balancing Authority and the Source—External Balancing Authority on the terms and conditions set forth in this Agreement; and

WHEREAS, SPP is a Regional Transmission Organization approved by the Federal Energy Regulatory Commission operating an Integrated Marketplace and is a NERC certified Balancing Authority; and

WHEREAS, the Source—External Balancing Authority has agreed to facilitate the delivery of power, generation or the transfer of load into the Integrated Marketplace from the Market Participant to the SPP Balancing Authority as defined below or the External Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined below; and

WHEREAS, Market Participant is responsible for generation or load outside of the boundaries of the SPP Balancing Authority Area and desires to participate in the Integrated Marketplace as an External Resource or load or the Market Participant is responsible for generation or load inside the SPP Balancing Authority Area and desires not to participate in the Integrated Marketplace; and

WHEREAS, the SPP Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant from the External Balancing Authority as defined below or the SPP Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined below; and

WHEREAS, Market Participant represents a generator operator or load serving entity located in the Eastern Interconnection and physically located within the balancing authority boundaries of the Source—External Balancing Authority or the SPP Balancing Authority; and

WHEREAS, Market Participant represents a generator operator or load serving entity registered with SPP and meeting all of the SPP qualifications in order to operate in the Integrated Marketplace and abiding by all the respective Market Protocols and rules as set forth by SPP.
NOW THEREFORE, in consideration of the mutual covenants and agreements in this Agreement and of other good and valuable consideration, the sufficiency and adequacy of which are hereby acknowledged, the Parties, intending to be legally bound, hereby agree as follows:

1. Creation of Non-Physical Pseudo-Tie Point. From and after the effective date hereof, the point at which non-physical pseudo-tie electrical interconnection is made between the Market Participant (Name of the Generation Facility generation or load) (Location) (the “Facility”) and the SPP Balancing Authority, which shall be defined in the one-line diagram attached hereto as Exhibit A, shall be a new non-physical pseudo-tie electrical interconnection point between the SPP Balancing Authority and the Source External Balancing Authority (the “Pseudo-Tie Point”), whereby any energy delivered from or consumed by the Facility for the account of the Source External Balancing Authority, shall be treated as a balancing authority interchange from between the Source–External Balancing Authority and the SPP Balancing Authority (for the avoidance of doubt, whether or not, at the time of delivery or consumption of such energy, the metering, data processing, telemetry and other equipment associated with the Pseudo-Tie Point is properly functioning). For the avoidance of doubt, the SPP Balancing Authority or the External Balancing Authority will not be taking title to any energy delivered from or consumed by the Facility at the Pseudo-Tie Point for the account of the Source Balancing Authority.

2. Implementation. Each Party shall design, construct, operate and maintain the equipment for which it is responsible under this Agreement, and shall take all other actions required of it, to create and have the Pseudo-Tie Point recognized by the SPP as a balancing authority interchange between the Source–External Balancing Authority and the SPP Balancing Authority for the purpose of allowing the Facility to be treated as being in the SPP Balancing Authority or the External Balancing Authority. Without limiting the foregoing, each Party shall undertake the design, construction, operation and maintenance for which it is responsible under this Agreement according to North American Electric Reliability Corporation standards. A basic block diagram of the communications equipment required for the Pseudo-Tie Point is set forth in Exhibit B. As among the Parties:

(a) The entity representing the generator in the Source–External Balancing Authority or the generator or load identified as energy resources located in the External Balancing Authority, shall register with SPP to become a Market Participant in the Integrated Marketplace. Registration shall be done in accordance with the SPP Market Protocols. Each Facility must be registered separately with SPP and registration information shall be provided to the External Balancing Authority. Market Participant must register its generator or load located in the SPP Balancing Authority as a Resource capable of supplying both Energy and qualified Operating Reserve products (Regulation Up, Regulation Down and/or Contingency Reserve).

(b) This Agreement does not provide for the reservation or sale of Firm Transmission Service under the SPP’s Open Access Transmission Tariff (“OATT”) or on any other transmission system. Market Participant shall secure and pay for all cost associated with transmission service, across all transmission service providers necessary to deliver or consume power from the Facility to the interface point with the SPP Balancing Authority or to the interface point with the External Balancing Authority.

(c) In order to supply Energy and qualified Operating Reserve products (Regulation-Up, Regulation-Down and/or Contingency Reserve) to the Integrated Marketplace or to transfer load to the Integrated Marketplace, the Market Participant shall secure Firm Transmission Service from where it is physically located through the path to the interface point with the
SPP Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting participation and for continued participation in the Energy and Operating Reserve Markets.

(d) In order to supply energy to the External Balancing Authority or to transfer load to the External Balancing Authority, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the External Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting participation in the movement of Resources and load out of the SPP Balancing Authority to the External Balancing Authority.

(ed) The use of this Agreement is intended for the purposes of providing Energy and qualified Operating Reserve products into the Energy and Operating Reserve Markets through submission of a Resource Offer.

(e) Market Participant is solely responsible for all requirements as set forth for a Market Participant in the Market Protocols.

(f) Market Participant shall design, construct, operate and maintain systems and communications equipment in order to: (i) receive SPP deployment instructions for generators pseudo-tying into the SPP Balancing Authority; (ii) account for load pseudo-tying into the SPP Balancing Authority; and (iii) enable SPP to account for congestion and losses associated with generators and loads pseudo-tying out of the SPP Balancing Authority in accordance with the Market Protocols.

(g) Market Participant shall design, construct, operate and maintain real-time and historical systems and communications equipment, at Market Participant’s expense, in order to provide the Source External Balancing Authority and the SPP Balancing Authority with the corresponding real-time pseudo-tie value. Market Participant’s systems shall provide this signal to the SPP Balancing Authority per the SPP Balancing Authority’s ICCP communication standards. Market Participant’s system shall provide this signal to the Source External Balancing Authority in a manner mutually agreed to between the Source External Balancing Authority and the Market Participant.

(h) SPP, in accordance with the Market Protocols, will provide the Market Participant commitment and dispatch instructions for generators pseudo-tying into the SPP Balancing Authority for participation in the Energy and Operating Reserve Markets consistent with such instructions issued to other registered Resources.

(i) For generators pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output Setpoint Instruction issued by the SPP to the Market Participant. The Market Participant shall simultaneously provide this value to the Source External Balancing Authority. Any Out-of-Merit Energy (“OOME”) requests as defined in the Market Protocols shall be included in the real-time pseudo-tie values.

–(k) For generators pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(lk) For loads pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.
For loads pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

The Source-External Balancing Authority and the SPP Balancing Authority will include the real time pseudo-tie value in their respective calculations of Net Actual Interchange (“NAI”) and Area Control Error (“ACE”).

If communication is lost between any of the Parties (including communication between SPP and the Market Participant), the Source-External Balancing Authority and the SPP Balancing Authority will freeze at the last known value and it is the responsibility of the Market Participant to verbally communicate changes of the real time pseudo-tie values with the other Parties consistent with the SPP instructions.

Market Participant shall notify Parties of any real-time circumstances that affect the Market Participant’s obligation or ability to meet the SPP Setpoint Instructions or External Balancing Authority instructions. If the Market Participant or the Source Balancing Authority deviate from the anticipated real time pseudo-tie value, the Market Participant is responsible for costs incurred by the SPP Balancing Authority. External generators and resources a generator pseudo-tying into the SPP Balancing Authority will be subject to the same penalties as internal generators under Attachment AE of the SPP Tariff. A generator pseudo-tying out the SPP Balancing Authority will be subject to the rules and procedures specified by the External Balancing Authority.

The Source-External Balancing Authority and the SPP Balancing Authority shall integrate the real time pseudo-tie value on an hourly basis and maintain this information for balancing authority checkout, inadvertent calculations and payback purposes in accordance with the applicable NERC standards. For generators and loads pseudo-tying into the SPP Balancing Authority, it is the responsibility of the Source-External Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the Source-External Balancing Authority’s final daily checkout with the SPP Balancing Authority. For generators and loads pseudo-tying out of the SPP Balancing Authority, it is the responsibility of the SPP Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the SPP Balancing Authority’s final daily checkout with the External Balancing Authority.

The SPP Balancing Authority shall act as the Meter Agent on behalf of the Market Participant for generators and loads pseudo-tying into or out of the SPP Balancing Authority Area is responsible for submission of settlement meter data for use in the settlement process of the Real-Time Balancing Market in accordance with the SPP Market Protocols. The SPP Balancing Authority shall perform this obligation under mutually agreed-upon by both the SPP Balancing Authority and the Market Participant. The settlement meter data will be the hourly integrated real time pseudo-tie value as calculated by the SPP Balancing Authority and checked out between the parties.

Except as otherwise provided in this Section 2, failure by the Market Participant to provide real-time pseudo-tie values in a timely manner and consistent with the SPP Setpoint Instruction constitutes a basis for the immediate suspension of this Agreement by the Source-External Balancing Authority or SPP Balancing Authority. In the event of such suspension, the Market Participant shall provide a remedy for the cause of the failure prior
to resumption of its participation in the Energy and Operating Reserve Markets. In the event of two suspensions within a thirty day period, this Agreement may be terminated, in accordance with Section 7 of this Agreement, at the sole discretion of the Source-External Balancing Authority or SPP Balancing Authority.

3. **Losses.** For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will be responsible for loss compensation to transmission provider(s) to deliver their energy to or receive their energy from the SPP Balancing Authority. Pseudo-tie value(s) will be considered net of losses external to SPP. Losses within the SPP Balancing Authority attributable to the Market Participant’s participation in the Energy and Operating Reserve Markets, including generators and loads pseudo-tying out of the SPP Balancing Authority, shall be handled in the same manner as other Energy and Operating Reserve Markets transactions.

4. **Compensation.** For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will compensate the Source-External Balancing Authority for the reasonable implementation and operations related costs borne by the Source-External Balancing Authority as a result of this Agreement unless the Market Participant and Source-External Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement. For generators and loads pseudo-tying out of the SPP Balancing Authority, Market Participant will compensate the SPP Balancing Authority for the reasonable implementation and operations related costs borne by the SPP Balancing Authority as a result of this Agreement unless the Market Participant and SPP Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement.

5. **Auditing.** Each Party reserves the right to audit records necessary to permit evaluation and verification of claims submitted, and the other Party’s compliance with this Agreement. The Parties shall retain for a period of three years all information and records relating to the performance of this Agreement. Each Party may examine and copy such information and records at the other Party’s premises during regular business hours and upon advance notice given no less than 15 calendar days prior to such examination.

6. **Effective Date.** The Agreement is effective upon full execution if it is not filed with the Commission. If the Agreement is filed with the Commission, then it is effective upon the later of the date of execution or the date allowed by the Commission. If the parties are unable to resolve any issues, SPP shall file an unexecuted agreement with the Commission, including all agreed-upon non-conforming deviations.

7. **Termination.** Notwithstanding Other than as provided in Section 2(p), this Agreement shall terminate on ________(Date), unless extended by agreement of all the Parties. Any Party shall have the right to terminate this Agreement upon ____ month’s notice, subject to receiving all necessary regulatory approvals for such termination.

8. **Governing Law.** The interpretation and performance of this Agreement and each of its provisions shall be governed and construed in accordance with the applicable Federal and/or State laws without regard its conflicts of laws provisions that would apply the laws of another jurisdiction.

9. **Interpretation.** In this Agreement:
(a) the words “include”, “includes” and “including” are deemed to be followed by the words “without limitation”;

(b) references to contracts, agreements and other documents and instruments shall be references to the same as amended, supplemented or otherwise modified from time to time;

(c) references to laws or standards and to terms defined in, and other provisions of, laws or standards shall be references to the same (or a successor to the same) as amended, supplemented or otherwise modified from time to time; and

(d) references to a person shall include its successors and permitted assigns and, in the case of a governmental or other authority (including SPP and the North American Electric Reliability Corporation), any person succeeding to its functions and capacities.

10. **Severability.** If any provision of this Agreement is held invalid, illegal or unenforceable in any jurisdiction, then, the Parties agree, to the fullest extent permitted by law, that the validity, legality and enforceability of the remaining provisions hereof in such or any other jurisdiction and of such provision in any other jurisdiction shall not in any way be affected or impaired thereby. With respect to the provision held invalid, illegal or unenforceable, the Parties will amend this Agreement as necessary to effect the original intent of the Parties as closely as possible.

11. **Complete Agreement; Amendments.** This Agreement constitutes the entire agreement among the Parties with respect to the subject matter of this Agreement and supersedes other prior agreements and understandings, both written and oral, among the Parties with respect to the subject matter of this Agreement. This Agreement may be amended, supplemented or otherwise modified only by an instrument in writing signed by all Parties.

12. **Other Obligations.** Nothing in this Agreement is intended to modify or change any obligations or rights under any tariff (including the SPP Tariff), any rate schedule, or any other contract. This Agreement does not in any way provide transmission service or address rates, terms or conditions of transmission service or indicate in any way that transmission service is available or properly awarded. A Party seeking transmission service must still go through the full tariff process to obtain transmission service. This Agreement also does not establish any generation as a designated network resource under the Tariff; the requirements of the Tariff still must be satisfied. Nor does this Agreement make any Party a Market Participant under the SPP Tariff. A Party seeking to become a Market Participant must apply to SPP under the terms of the SPP Tariff and nothing in this Agreement affects its rights or obligations as a Market Participant.

13. **Commission Filing.** If unchanged, a signed version of this form agreement shall not be filed with the Commission. SPP will simply report the existence of a signed agreement in its quarterly reports. If the form agreement is substantively changed, then SPP shall file the revised form agreement with the Commission. The Parties shall be bound to the terms accepted or ordered by the Commission.

14. **Modification.** Nothing in this Agreement is intended to modify or limit the right of SPP to submit under FPA Section 205 or Section 206 unilateral changes to this Agreement (both the form Agreement and any signed agreement); the right of any other Party to seek unilateral changes under FPA Section 206, or the right of the Federal Energy Regulatory Commission to accept any FPA Section 205 filing or to make changes under FPA Section 206 or to initiate proceedings under FPA Section 206.
15. **Charges.** The provisions in this Agreement providing for compensation do not authorize Commission regulated public utilities to impose charges without a separately filed tariff or rate schedule being accepted by the Commission.

16. **Disputes.** Any disputes under this Agreement shall first be resolved pursuant to the dispute resolution procedures in the SPP’s Open Access Transmission Tariff. Any disputes may be brought to the Commission.

17. **Breach.** If any Party breaches the terms of this Agreement, then a non-breaching Party may seek any relief it believes is appropriate at the Commission. A breach is considered a substantive violation of this Agreement. Prior to pursuing a remedy at the Commission for a breach, a non-breaching Party shall provide five business days notice of the breach to the breaching Party. If the breaching Party does not eliminate the breach within five (5) business days after the notice is received by the breaching Party, then the non-breaching Party may pursue its remedies at the Commission.

18. **Counterparts.** This Agreement may be executed in one or more counterparts, each of which shall be an original but all of which, taken together, shall constitute only one legal instrument. It shall not be necessary in making proof of this Agreement to produce or account for more than one counterpart. The delivery of an executed counterpart of this Agreement by facsimile shall be deemed to be valid delivery thereof.
The Parties have caused this Agreement to be signed by their authorized representatives on the day and year first above written.

**Source-External Balancing Authority**

By: __________________________
   Name: ______________________
   Title: ______________________

**SPP Balancing Authority**

By: __________________________
   Name: ______________________
   Title: ______________________

**Market Participant**

By: __________________________
   Name: ______________________
   Title: ______________________

| By: __________________________ |
| Name: ______________________   |
| Title: ______________________  |

**Southwest Power Pool, Inc. (SPP)**

*Revised Proposed Criteria Language Revision*

N/A
<table>
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<tr>
<th>PRR No.</th>
<th>Marketplace-PRR101</th>
<th>PRR Title</th>
<th>Combined Cycle Enhanced Design</th>
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### Timeline

- [x] Normal
- [ ] Expedited
- [ ] Urgent Action

Provide explanation if Expedited and/or Urgent Action is selected:

### Recommendation Action

- [x] Approve
- [ ] Reject
- [ ] Require additional information
- [ ] Defer
- [ ] Refer

### Impact Analysis Required

- [ ] Yes – If yes, estimated cost:
- [x] No

SPP Staff will complete this section.

### Protocol Section(s) Requiring Revision

- Section No.: 1., 4.2.2.1, 4.2.2.5.3, 4.3.1.2, 4.3.2.2, 4.3.2.4, 4.4.1.2, 4.4.1.4, 4.4.2.1, 4.5.8.12, 4.5.9, 4.5.9.8, 4.5.9.10, 6.1.7, 8.2.2.6 (new), Appendix D (12.)
- Title: Glossary, Resource Offer Parameters, Combined Cycle Resource, DA Market Execution; Day-Ahead RUC Execution, Update Current Operating Plan, Intra-Day RUC Execution, Update Current Operating Plan, Managing Regulation Control Status Prior to Operating Hour, Day-Ahead Make-Whole-Payment Amount, Real-Time Balancing Market Settlement, RUC Make-Whole-Payment Amount, RUC Make-Whole-Payment Distribution Amount, Combined Cycle Resource, Mitigation Measures for Transition State Offers (new), Appendix D (Real Time Data Reporting to SPP Balancing Authority)
- Protocol Version: 15.0a

### Type of Revision

- [ ] Correction/Clean-Up
- [x] Clarification
- [ ] Design Change

### Timeline

- [x] Go-Live
- [ ] Post Go-Live

### Revision Description

This MPRR allows Combined Cycle Resources to be registered and modeled in the Integrated Marketplace with a configuration-based option

### Tariff Implications or Changes

- [x] Yes – Section No: (Include a summary of impact and/or specific changes)

Attachment AE Section 1 Definitions; 2.9 Combined Cycle Resource; 4.1 Offer Submittal; 4.1.2.2 Combined Cycle Resource; 5.1.2 Day-Ahead Market Execution; 5.2.2 Day-Ahead Reliability Unit Commitment Execution; 5.2.3 Day-Ahead Reliability Unit Commitment Results; 6.1.2 Intra-Day Reliability Unit Commitment Execution; 6.1.3 Intra-Day Reliability Unit Commitment Results; 8.5.9 Day-Ahead Make Whole Payment Amount; 8.6.5 Reliability Unit Commitment Make Whole Payment Amount; 8.6.7 Reliability Unit Commitment Make Whole Payment Distribution Amount; Attachment AF Section 2 Definitions; 3.5 Mitigation Measures for Transition State Offers (new); 3.9 Sanctions for Noncompliance with the Day-Ahead Market Must Offer Requirement;

- [ ] No
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<th>Criteria Impact or Changes</th>
<th>☐ Yes – Section No: (Include a summary of impact and/or specific changes)</th>
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<th>MWG Review</th>
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<tr>
<td>PRR Recommendation</td>
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<tr>
<td>Date of Vote: 8/6/2013</td>
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<tr>
<td>Opposed: N/A</td>
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<td>Abstained: N/A</td>
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| RTWG Review              |
| Date of Vote: 9/11/2013  |
| Vote: Approved with modifications |

| ORWG Review              |
| Date of Vote: 8/30/2013  |
| Vote: Approved           |

| MOPC Recommendation      |
| Date of Vote: 9/17/2013  |
| Vote: Unanimously Approved RTWG modifications |

| Board Review             |
| Date of Vote:           |
| Vote:                   |

**Date**

10/5/2012

**Sponsor**

Name: Debbie James

E-mail Address: djames@spp.org

Company: Southwest Power Pool

Phone Number: 501.614.3577

**Comments Received**

**Comment Author**

Debbie James (SPP)

**Date**

10/16/2012

**Comment Description**

These comments update Protocol language (see Sections 4.5.9.8(4)(a.2)) to correct the calculation of minimum output energy cost to include proper treatment of Enhanced Combined Cycle units that were cleared in the DA Market and then moved into a higher configuration in Real-Time. These comments also add Tariff language to implement the Enhanced CC design. Tariff Sections impacted were Attachment AE (1.1-Definitions, 2.9-Combined Cycle Resource, 4.1-Offer Submittal, 4.1.2.2-Combined Cycle Resource, 8.5.9-Day-Ahead Make Whole Payment Amount, 8.6.5-Reliability Unit Commitment Make Whole Payment Amount, 8.6.7-Reliability Unit Commitment Make Whole Payment Distribution Amount) and Attachment AF (3.2.5-Mitigation Measures for Transition State Offers).

**Comment Status**

MWG approved the MPRR as modified. The approved language is reflected in this recommendation report.

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**Comments Received**

**Comment Author**

Debbie James (SPP)

**Date**

7/22/2013

**Comment Description**

1. New Offer Parameters were added for better management of a combined cycle Plant minimum run time along with additional explanation as to the impact of these new parameters on commitment.

2. New RUC MWP provisions were added to allow for recovery of costs associated with the buying back of DA Market Operating Reserve positions.
during transition mode (if RT MCP greater than DA MCP, this difference multiplied by DA Market cleared OR is eligible for recovery).
3. Clarified submitted Transition Mode Status via ICCP.

### Comment Status
MWG approved the MPRR as modified. The approved language is reflected in this recommendation report.

### Comments Received

<table>
<thead>
<tr>
<th>Comment Author</th>
<th>Debbie James</th>
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<td>Date</td>
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<td>1. New Offer Parameters were added for better management of a combined cycle Plant minimum run time along with additional explanation as to the impact of these new parameters on commitment.</td>
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<td>2. New RUC MWP provisions were added to allow for recovery of costs associated with the buying back of DA Market Operating Reserve positions during transition mode (if RT MCP greater than DA MCP, this difference multiplied by DA Market cleared OR is eligible for recovery). Modifications were added to correct the calculations.</td>
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<td>3. Clarified submitted Transition Mode Status via ICCP.</td>
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<td>4. Additional grammatical and clarification changes were made to match the Protocol language to the Tariff language.</td>
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<tr>
<td>5. New DA Market MWP provisions were added to allow for recovery of costs associated with the buying back of DA Market Operating Reserve positions during transition mode (if RT MCP greater than DA MCP, this difference multiplied by DA Market cleared OR is eligible for recovery) when there is no RUC MWP eligibility.</td>
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<td>6. Clarifications were added regarding Day-Ahead Market clearing of Regulation-Up and/or Regulation Down during hours in which transitions occur (no regulation clearing in any hour in which transitions occur) and Day-Ahead Market clearing of Contingency Reserve during hours in which transitions occur (if transition time is greater than 30 minutes, no Contingency Reserve clearing in that hour).</td>
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### Comment Status
MWG approved the MPRR as modified. The approved language is reflected in this recommendation report.

### Comments Received

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<thead>
<tr>
<th>Comment Author</th>
<th>Brenda Fricano on behalf of RTWG</th>
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<tr>
<td>Date</td>
<td>9/11/2013</td>
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<tr>
<th>Comment Description</th>
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<tr>
<td>RTWG made changes to Tariff for MPRR101 that include; changes to the definitions of Commitment Instruction and Mitigated Transition State Offer, changes to grammatical errors and wordsmithing.</td>
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<tr>
<td>RTWG changes are highlighted in Yellow.</td>
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### Proposed Protocol Language Revision

1. **Glossary**

   **Grandfathered Agreement (GFA)**
   
   As defined as Grandfathered Agreements or Transactions in the SPP Tariff.

   **Group Minimum Run Time**
   
   As defined in Attachment AE of the SPP Tariff
Mitigated Resource Offer

For a Resource, the combination of its Mitigated Start-Up Offer, Mitigated No-Load Offer, Mitigated Energy Offer Curve, Mitigated Regulation-Up Offer, Mitigated Regulation-Down Offer, Mitigated Spinning Reserve Offer, and Mitigated Supplemental Reserve Offer. The Mitigated Resource Offer Parameters are developed in accordance with guidelines detailed in Appendix G and are intended to capture the incremental cost, including the appropriate application of opportunity costs, of providing each service to the SPP Energy and Operating Reserve Markets.

Mitigated Supplemental Reserve Offer

The mitigated offer, where such offers are developed in accordance with guidelines detailed in Appendix G, at which a Supplemental Qualified Resource offers to sell Supplemental Reserve in dollars per MW.

Mitigated Transition State Offer

As defined in Attachment AE of the SPP Tariff.

Parallel Flow

Flow on the Transmission System not scheduled with SPP caused by entities external to the SPP Market Footprint. (Also known as loop flow.)

Plant Minimum Run Time

As defined in Attachment AE of the SPP Tariff.

Resource Offer

For a Resource, the combination of its Start-Up Offer, No-Load Offer, Energy Offer Curve, Transition State Offer, Regulation-Up Offer, Regulation-Down Offer, Spinning Reserve Offer and Supplemental Reserve Offer.

Trading Hub

A Settlement Location consisting of an aggregation of Price Nodes developed for financial and trading purposes.[MPRR90.1]

Transition State Offer

As defined in Attachment AE of the SPP Tariff.

Transition State Time

As defined in Attachment AE of the SPP Tariff.

Transmission Congestion Right (TCR)

A financial right that entitles the holder to a share of the congestion revenue collected in the Day-Ahead Market.
4.2.2.1 Resource Offer Parameters

The following Resource Offer parameters must be submitted to constitute a valid offer for use in either the DA Market or RTBM:

1. Resource Name (as specified during Market Registration and cannot be changed as part of Resource Offer submittal);
2. Start-Up Offer ($/Start, Hot, Intermediate and Cold – Unit Commitment)\(^1\);
3. Mitigated Start-Up Offer ($/Start, Hot, Intermediate and Cold – Unit Commitment);
4. No-Load Offer ($/Hour)\(^1\);
5. Mitigated No-Load Offer ($/Hour);
6. Energy Offer Curve (MW, $/MWh, up to 10 price/quantity pairs, slope or block option, monotonically non-decreasing, block and slope pairs may not coexist – the Resource Offer in effect for any given period of time must be comprised of all block or all slope price/quantity pairs):
   a. The price of all MWhs below the first pricing point MWh is equal to the first pricing point price. The price of all MWhs above the last pricing point MWh is equal to the last pricing point price.
   b. Under the slope option, the set of price points that are submitted are used as the beginning and ending values for calculating a linear slope for each set of beginning and ending values. Therefore, each MW between the two price points has a different price due to the interpolation of the submitted price points. Under the block option, each MW between the two MW points is offered at the price of the larger MW point. Exhibit 4-4 illustrates Energy Offer Curves developed from submitted price/MWh pairs for both the slope and block options.

\(^1\) For Asset Owners that have registered a JOU under the Combined Resource Option (see Section 6.1.7.2), this value must be submitted by the specified Asset Owner and represents the value for the entire Physical JOU Resource.
(7) Mitigated Energy Offer Curve (MW, $/MWh, up to 10 price/quantity pairs, slope or block option, monotonically non-decreasing, block and slope pairs may not coexist – the Resource Offer in effect for any given period of time must be comprised of all block or all slope price/quantity pairs);

(8) Regulation-Up Offer ($/MW);

(9) Mitigated Regulation-Up offer ($/MW);

(10) Regulation-Down Offer ($/MW);

(11) Mitigated Regulation-Down Offer ($/MW);

(12) Spinning Reserve Offer ($/MW);

(13) Mitigated Spinning Reserve Offer ($/MW);

(14) Supplemental Reserve Offer ($/MW);

(15) Mitigated Supplemental Reserve Offer ($/MW)

(16) Sync-To-Min Time (hours:minutes – Unit Commitment)\(^1\);

(17) Min-To-Off Time (hours:minutes – Unit Commitment)\(^1\);

(18) Start-Up Time (hours:minutes, Hot, Intermediate, Cold – Unit Commitment)\(^1\);

(19) Hot to Intermediate Time (hours:minutes– Unit Commitment)\(^1\);

(20) Hot to Cold Time (hours:minutes– Unit Commitment)\(^1\);

(21) Maximum Daily Starts (Unit Commitment)\(^1\);

(22) Maximum Weekly Starts – rolling 7-day (Unit Commitment)\(^1\);

(23) Maximum Daily Energy (MWh – Unit Commitment)\(^1\);

(24) Minimum Run Time (hours:minutes– Unit Commitment)\(^1\);

(25) Group Minimum Run Time (hours:minutes– Unit Commitment) - Only applicable to combined cycle Resources that have registered under the option described under Section 6.7.1(4);

(26) Plant Minimum Run Time (hours:minutes– Unit Commitment) - Only applicable to combined cycle Resources that have registered under the option described under Section 6.7.1(4);

(27) Maximum Run Time (hours:minutes– Unit Commitment)\(^1\);
Minimum Down Time (hours:minutes – Unit Commitment)\(^1\);

Minimum Emergency Capacity Operating Limit (MW);

Minimum Emergency Capacity Run Time (hours:minutes – Operations Information);

Minimum Normal Capacity Operating Limit (MW);

Minimum Economic Capacity Operating Limit (MW);

Minimum Regulation Capacity Operating Limit (MW);

Maximum Regulation Capacity Operating Limit (MW);

Maximum Economic Capacity Operating Limit (MW);

Maximum Normal Capacity Operating Limit (MW);

Maximum Emergency Capacity Operating Limit (MW);

Maximum Emergency Capacity Run Time (hours:minutes – Operations Information);

Maximum Quick-Start Response Limit (MW, this represents the maximum amount of Supplemental Reserve that may be supplied by an off-line Quick-Start Resource – Unit Commitment)\(^1\);

Ramp-Rate-Up (curve, MW/Minute - for use when the Resource is not selected for Regulation-Up and/or Regulation-Down clearing and dispatched in the up direction). Ramp-Rate-Up submittal is through a segmented profile as follows. Each profile will require at least one (1) segment and may have up to \(n\) segments where \(n\) will be defined by SPP, initially set to ten (10);

(a) Breakpoint Limit 1 – Resource MW output at which segment 1 Ramp-Rate-Up will apply. In the RTBM, if the actual measured MW during deployment is less than the Breakpoint Limit 1, the Ramp-Rate-Up in Block 1 will apply back to the actual measured MW.

(b) Block 1 Ramp Rate Up – Rate at which Resource can change output upward in MW/min at output levels greater than or equal to Breakpoint Limit 1.

(c) Block 1 Ramp Rate Emergency – Rate at which Resource can change output upward in MW/min at output levels greater than or equal to Breakpoint Limit 1 during an Emergency.

(d) Breakpoint Limit \(n\) – Resource MW output at which Ramp-Rate-Up changes from previous segment values to segment \(n\) values.

(e) Block \(n\) Ramp-Rate-Up – Rate at which Resource can change output upward in MW/min at output levels greater than or equal to the Breakpoint Limit \(n\)

(f) Block \(n\) Ramp-Rate-Up Emergency – Rate at which Resource can change output upward in MW/min at output levels greater than the Breakpoint Limit \(n\) and less than Breakpoint Limit \(n+1\) during an Emergency.

Ramp-Rate-Down (curve, MW/Minute - for use when the Resource is not selected for Regulation-Up and/or Regulation-Down clearing and dispatched in the Down direction).
Ramp-Rate-Down submittal is through a segmented profile as follows. Each profile will require at least one (1) segment and may have up to \( n \) segments where \( n \) will be defined by SPP, initially set to ten (10);

(a) Breakpoint Limit 1 – Resource MW output at which segment 1 Ramp-Rate-Down will apply. In the RTBM, if the actual measured MW during deployment is less than the Breakpoint Limit 1, the Ramp-Rate-Down in Block 1 will apply back to the actual measured MW.

(b) Block 1 Ramp Rate Down – Rate at which Resource can change output downward in MW/min at output levels greater than or equal to Breakpoint Limit 1.

(c) Block 1 Ramp-Rate-Down Emergency – Rate at which Resource can change output downward in MW/min at output levels greater than or equal to Breakpoint Limit 1 during an Emergency.

(d) Breakpoint Limit \( n \) – Resource MW output at which Ramp-Rate-Down changes from previous segment values to segment \( n \) values.

(e) Block \( n \) Ramp-Rate-Down – Rate at which Resource can change output downward in MW/min at output levels greater than or equal to the Breakpoint Limit \( n \).

(f) Block \( n \) Ramp-Rate-Down Emergency – Rate at which Resource can change output downward in MW/min at output levels greater than the Breakpoint Limit \( n \) and less than Breakpoint Limit \( n+1 \) during an Emergency

(40) Turn-Around Ramp Rate Factor (a percentage between 0% and 100%). This factor is used to adjust a Resource’s Ramp-Rate-Up or Ramp-Rate-Down in a Dispatch Interval for which a Resource’s Energy Dispatch Instruction has changed direction from the previous Dispatch Interval and is only used in the RTBM. For example, if in the last Dispatch Interval the Resource’s Dispatch Instruction was in the up direction and in the current Dispatch Interval its Dispatch Instruction is in the down direction, this factor is applied to the Resource’s Ramp-Rate-Down prior to the calculation of the actual Dispatch Instruction in that Dispatch Interval. A submittal of 0% creates a Ramp-Rate-Up or Ramp-Rate-Down of 0 MW/Min and a submittal of 100% indicates no change to the Resource’s Ramp-Rate-Up or Ramp-Rate-Down. Additionally, the Turn-Around Ramp Rate Factor is applied to limit on-line Contingency Reserve clearing when a Resource’s Energy Dispatch Instruction in the previous Dispatch Interval was in the down direction. The Turn-Around Ramp Rate Factor does not apply to a Resource that is selected as available to be cleared for Regulation-Up and/or Regulation-Down;

(41) Regulation Ramp Rate (curve, MW/Minute - for use when the Resource is selected for Regulation-Up and/or Regulation-Down clearing). Regulation Ramp Rate submittal is through a segmented profile as follows. Each profile will require at least one (1) segment and may have up to \( n \) segments where \( n \) will be defined by SPP, initially set to ten (10);
(a) Breakpoint Limit 1 – Resource MW output at which segment 1 Regulation Ramp Rate will apply. In the RTBM, if the actual measured MW during deployment is less than the Breakpoint Limit 1, the Regulation Ramp Rate in Block 1 will apply back to the actual measured MW.

(b) Block 1 Regulation Ramp Rate – Rate at which a Resource on Automatic Generation Control can change output in the up and down direction in MW/min at output levels greater than or equal to Breakpoint Limit 1.

(c) Breakpoint Limit \( n \) – Resource MW output at which Regulation Ramp Rate changes from previous segment values to segment \( n \) values.

(d) Block \( n \) Regulation Ramp Rate – Rate at which Resource on Automatic Generation Control can change output in the up and down direction in MW/min at output levels greater than or equal to the Breakpoint Limit \( n \).

\( 42 \) Contingency Reserve Ramp Rate (curve, MW/Minute). Contingency Reserve Ramp Rate submittal is through a segmented profile as follows. Each profile will require at least one (1) segment and may have up to \( n \) segments where \( n \) will be defined by SPP, initially set to ten (10);

a. Breakpoint Limit 1 – Resource MW output at which segment 1 Contingency Reserve Ramp Rate will apply. In the RTBM, if the actual measured MW during deployment is less than the Breakpoint Limit 1, the Contingency Reserve Ramp Rate in Block 1 will apply back to the actual measured MW.

b. Block 1 Contingency Reserve Ramp Rate – Rate at which a Resource not on Automatic Generation Control can change output in the up direction in MW/min when deploying Contingency Reserve at output levels greater than or equal to Breakpoint Limit 1.

c. Breakpoint Limit \( n \) – Resource MW output at which Contingency Reserve Ramp Rate changes from previous segment values to segment \( n \) values.

d. Block \( n \) Contingency Reserve Ramp Rate – Rate at which Resource not on Automatic Generation Control can change output in the up direction in MW/min when deploying Contingency Reserve at output levels greater than or equal to the Breakpoint Limit \( n \).

\( 45 \) Resource Status (see Section 4.2.2.2); and

\( 46 \) Transition State Offer (Only applicable to combined cycle Resource. See Section 4.2.2.5.3(4));

\( 47 \) Mitigated Transition State Offer (Only applicable to combined cycle Resource);

\( 48 \) Transition State Time (Only applicable to combined cycle Resource. See Section 4.2.2.5.3(4));

\( 49 \) JOU Ownership Share (Unit Commitment - see Section 4.2.2.5.4).

4.2.2.5.3 Combined Cycle Resource
Combined \( C_{\text{cycle}} \) modeling will be accommodated as follows for Resources registered as a \( C_{\text{combined cycle}} \) Resource. Market Participants that jointly own a \( C_{\text{combined cycle}} \) Resource that desire to use the Jointly Owned Unit modeling options described under Section 4.2.2.5.4 must register as a Jointly Owned Unit and cannot register the Resource as a \( C_{\text{combined cycle}} \) Resource.

(i) Market Participants will have to select from one of the three four following options regarding submitting Resource Offers for their registered \( C_{\text{combined cycle}} \) Resources which will need to be declared during asset registration as described under Section 6.1.7:

(1)(a) A Resource Offer may be submitted for a single aggregate \( C_{\text{combined cycle}} \) Resource, where the aggregate will represent a Market Participant selected operating configuration of combustion turbines (CT) and steams turbines (ST) (i.e. a 1CT x 1ST, 2CT x 1ST, 3CT x 1ST, etc). Under this option, the \( C_{\text{combined cycle}} \) Resource will be committed, dispatched and settled the same as any other Resource; or

(b) A Resource Offer may be submitted for each \( C_{\text{combined cycle}} \) Resource combustion turbine and/or steam turbine and each component will be committed and dispatched independently and settled the same as any other single Resource; or

(c) A Resource Offer may be submitted for each pseudo \( C_{\text{combined cycle}} \) Resource, where each pseudo \( C_{\text{combined cycle}} \) Resource will represent the combination of one combustion turbine and a portion of the steam turbine. Under this option, each pseudo \( C_{\text{combined cycle}} \) Resource must be capable of being committed and dispatched independently the same as any other Resource and each pseudo \( C_{\text{combined cycle}} \) Resource will be settled the same as any other Resource.

(4) A Resource Offer may be submitted for each combined cycle Resource configuration, where each configuration is defined during market registration.

(a) Each configuration will be modeled as a separate Resource in order to select the most economic configuration for economic commitment and dispatch. Configuration rules defining which Resources are eligible for Start-Up, what configurations are valid when moving from one configuration to another, and transition costs and minimum run times associated with moving between configurations are defined during market registration as described under Section 6.1.7. The Offer parameters described under Sections 4.2.2.1 and 4.2.2.2 must be submitted for each configuration with the following exceptions and additional parameters:

(b) Start-Up Offer is only applicable to valid configurations associated with committing the Resource from an off-line state to an on-line state; and

(c) Transition State Offers and Transition State Times are only valid for moving from one configuration to another once the Resource becomes a Synchronized Resource.
(d) For the DA Market, configuration changes will be determined on an hourly basis. For the RTBM, a configuration will be determined prior to the Operating Hour and that configuration will generally remain fixed for dispatch purposes within the Operating Hour. However, SPP may make configuration changes within the Operating Hour to address a reliability issue to the extent that the transition can be accomplished in a timely manner.

(e) Meter data for use in RTBM settlement must be submitted at the combined cycle Resource plant output level and is not dependent upon which configuration the Resource has operated under.

(f) If the combined cycle Resource is committed by SPP in the DA Market, and during the DA Market Commitment Period the Resource was moved from one configuration to another within the commitment period, any transitions costs incurred will be included in the DA Market make-whole-payment calculation described under Section 4.5.8.12. Moving from one configuration to another will not be considered as the start of a new DA Market Commitment Period.

(g) If the combined cycle Resource is not committed by SPP in the DA Market and is committed during the RUC process and during the RUC Commitment Period the Resource was moved from one configuration to another within the commitment period, any transitions costs incurred will be included in the RUC make-whole-payment calculation described under Section 4.5.9.8. Moving from one configuration to another will not be considered as the start of a new RUC Commitment Period.

(h) If the combined cycle Resource was committed in the DA Market and then, during an RTBM hour within the DA Market Commitment Period, the Resource is moved by SPP into a configuration that is different from the configuration used in the DA Market Commitment period, any transitional costs incurred are eligible for recovery as described under Section 4.5.9.8.

### 4.3.1.2 DA Market Execution

SPP clears the Day-Ahead Market for each hour of the upcoming Operating Day based on the inputs described above. A simultaneous co-optimization methodology, utilizing the SCUC and SCED algorithms is employed to simultaneously perform the following tasks:

1. Commit offered Resources, Import Interchange Transaction Offers and Virtual Energy Offers using the SCUC algorithm to meet the Demand Bids, Virtual Energy Bids, Export Interchange Transactions Bids and Operating Reserve requirements at least cost throughout the projected upcoming Operating Day while respecting Resource operating constraints and transmission constraints;
The DA Market SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market and Self, including Resources committed in the Multi-Day Reliability Assessment process, only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up) and down to the Resources Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down). In addition, combined cycle Resources modeled as described under Section 4.2.2.5.3(4) are not eligible for regulation selection in any hour in which they are transitioning from one configuration to another.

(i) If this capacity is not sufficient to meet the fixed Demand Bids and fixed Export Interchange Transaction Bids plus Operating Reserve requirements on a system-wide basis, the DA Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limit and/or commit Resources’ with a Commit Status of Reliability on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

(ii) If there is a capacity surplus on a system-wide basis calculated as the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transaction Offers and the Regulation-Down requirement that is in excess of the sum of Fixed Demand Bids and fixed Export Interchange Transaction Bids, the DA Market SCUC algorithm will, in priority order (1) curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limit on an economic basis until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement to the extent possible.

(b) To the extent that a particular reliability issue cannot be directly addressed within the DA Market SCUC algorithm as described under subsection (i) and (ii) above, SPP may manually commit Resources to alleviate such reliability issues. SPP will re-run the DA Market SCUC algorithm after such manual commitments, time permitting, and will notify the Market Participants that units were manually committed. The SCED algorithm will be run based on the manual commitment to produce a final market solution.

(2) Using the commitment results from the SCUC, clear Resource Offers and Import Interchange Transaction Offers to meet Demand Bids, Virtual Energy Bids, Export Interchange Transaction Bids and Operating Reserve requirements at minimum cost for each hour of the upcoming Operating Day using the SCED algorithm while respecting Resource operating constraints and transmission constraints.
(a) The SCED algorithm includes marginal loss sensitivity factors which approximate the change in marginal system losses for a change in Energy dispatch. Inclusion of these factors further optimizes the Energy dispatch and reduces overall production costs.

(b) In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, SPP must apply Violation Relaxation Limits (VRLs) in SCED as described under Section 4.1.4.

(c) To ensure rational pricing of cleared Operating Reserve products, the SCED algorithm will include product substitution logic as follows:

(i) Any Regulation-Up Offers remaining once the Regulation-Up Requirement is satisfied may be used to meet Contingency Reserve requirements if Regulation-Up Offer is more economic or is required to meet the overall Operating Reserve requirement;

(ii) Any Spinning Reserve Offers remaining once the Spinning Reserve Requirement is satisfied may be used to meet Supplemental Reserve requirements if Spinning Reserve Offer is more economic or is required to meet the overall Operating Reserve requirement;

(iii) The product substitution logic ensures that the MCP for Regulation-Up is always greater than or equal to the Spinning Reserve MCP and that the Spinning Reserve MCP is always greater than or equal to the Supplemental Reserve MCP.

(d) To ensure that Market Participants are indifferent as to whether they are cleared for Energy or Operating Reserve, the co-optimization logic will provide through the Shadow Price calculation Market Clearing Prices for Operating Reserve that include any lost opportunity costs incurred as a result of Operating Reserve clearing.

(e) Combined cycle Resources modeled as described under Section 4.2.2.5.3(4) with Transition Times greater than 30 minutes are not eligible to clear Contingency Reserve in any hour in which they are transitioning from one configuration to another.

4.3.2.2 Day-Ahead RUC Execution

Using the inputs described above, SPP performs a capacity adequacy analysis for the upcoming Operating Day using the SCUC algorithm. The capacity adequacy analysis provides advisory information to the SPP Operators.

(1) The objective of the SCUC is to commit Resources to meet the SPP Mid-Term Load Forecast and Operating Reserve requirements over the Operating Day such that commitment costs are minimized while adhering to transmission system security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers;
Commitment costs are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined in the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the RUC SCUC in making commitment decisions;

The SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market or Self only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up) and down to the Resources Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down). In addition, combined cycle Resources modeled as described under Section 4.2.2.5.3(4) are not eligible for regulation selection in any hour in which they are transitioning from one configuration to another.

(a) If this capacity is not sufficient to meet the system-wide SPP Mid-Term Load Forecast plus Operating Reserve requirements, the SCUC algorithm study will, in priority order:
   (1) curtail non-firm Export Interchange Transactions until the capacity shortage is eliminated; (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limit and/or commit Resources’ with a Commit Status of Reliability on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

(b) If the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transaction Offers and the system-wide Regulation-Down requirement is in excess of the sum of the SPP system-wide Mid-Term Load Forecast and fixed Export Interchange Transactions, the RUC SCUC algorithm study will, in priority order: (1) curtail non-firm fixed Import Interchange Transactions until the capacity surplus is eliminated; (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limit on an economic basis until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement to the extent possible; (3) de-commit Resources that were committed in the DA Market with a Commit Status of Market until the capacity surplus in eliminated; and (4) de-commit Self-Committed Resources until the capacity surplus in eliminated.

   (i) If there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, SCUC may commit additional Resources and/or de-commit Resources to relieve the constraints provided that any commitment changes do not aggravate the excess capacity situation.

(c) To the extent that a particular reliability issue cannot be directly addressed within the SCUC algorithm as described under subsection (a) and (b) above, SPP may manually commit Resources including Resources with a Commit Status of Reliability, and
de-commit Resources, including Resources with a Commit Status of Self, to alleviate such reliability issues in accordance with its authority as Reliability Coordinator.

1) As Local Reliability Issue emergency condition may arise within the operating area of a local transmission operator that may involve elements not monitored by SPP. Such emergencies—Local Reliability Issues may require out of merit commitment, decommitment or dispatch instructions to be issued to one or more Resources to resolve the Local Reliability Issue. In such cases, the local transmission operator shall request SPP to issue such instructions. To the extent that SPP commits a Resource to address a Local Reliability Issue at the request of a local transmission operator such Resource shall be eligible for compensation in the same manner as any other Resource. Recovery of such compensation shall be collected locally as described under Section 4.5.9.10. If the SPP determines that the instructions were required for regional reliability, recovery of such compensation shall be collected regionally as described under Section 4.5.9.10.

Any curtailment of schedules, use of Reliability Status Resources or use of Emergency operating limits by the RUC algorithms will only be advisory information to the SPP RUC Operators. Day-Ahead RUC and Intra-Day RUC Operators will determine which of these options should be acted on and when as described in the Day-Ahead and Intra-Day RUC Results sections.

4.3.2.4 Update Current Operating Plan

Using the results from the Day-Ahead RUC analysis, SPP will update the Current Operating Plan and will issue start-up and shut-down orders to Resources other than DVERs and NDVERs for which SPP is calculating an output forecast (these Resources are always assumed to be self-committed if available) as appropriate. SPP can only de-commit DA Market committed Resources or move a DA Market committed combined cycle Resource that has been registered to submit configuration based offers as described under Section 4.2.2.5.3(4) into a lower configuration to address an anticipated excess supply condition as described under Section 4.3.2.2(3)(b) and/or to address any other Emergency conditions. If SPP de-commits an SPP committed Resource or moves a combined cycle resource into a lower configuration for any hour of the DA Market commitment schedule, and causes that Resource to buy back its Energy and/or Operating Reserve position at RTBM prices that exceed the DA Market prices for the comparable products, then that Resource is eligible for compensation under Section 4.5.9.9.

4.4.1.2 Intra-Day RUC Execution

Using the inputs described above, SPP performs a capacity adequacy analysis for the upcoming Operating Day and throughout the Operating Day using a SCUC algorithm. The capacity adequacy analysis provides advisory information to the SPP Operators.
(1) The objective of the SCUC is to commit Resources to meet the SPP Mid-Term Load Forecast and Operating Reserve requirements over the Operating Day such that commitment costs are minimized while adhering to transmission system security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers;

(2) Commitment costs are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined on the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the RUC SCUC in making commitment decisions;

(3) The SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market or Self only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up) and down to the Resources Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down). In addition, combined cycle Resources modeled as described under Section 4.2.2.5.3(4) are not eligible for regulation selection in any hour in which they are transitioning from one configuration to another.

   (a) If this capacity is not sufficient to meet the system-wide SPP Mid-Term Load Forecast plus Operating Reserve requirements, the SCUC algorithm study will, in priority order: (1) curtail non-firm Export Interchange Transactions until the capacity shortage is eliminated; (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limit and/or commit Resources’ with a Commit Status of Reliability on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

   (b) If the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transaction Offers and the system-wide Regulation-Down requirement is in excess of the sum of the SPP system-wide Mid-Term Load Forecast and fixed Export Interchange Transactions, the SCUC algorithm study will, in priority order: (1) curtail non-firm fixed Import Interchange Transactions until the capacity surplus is eliminated; (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limit on an economic basis until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement to the extent possible; (3) de-commit Resources that were committed in the DA Market with a Commit Status of Market until the capacity surplus is eliminated; and (4) de-commit Self-Committed Resources that were committed following the Day-Ahead RUC process until the capacity surplus is eliminated.

   (i) If there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, RUC may commit additional Resources to relieve the constraints provided that the additional commitment does not aggravate the excess capacity situation.
To the extent that a particular reliability issue cannot be directly addressed within the SCUC algorithm as described under subsection (a) and (b) above, SPP may manually commit Resources, including Resources with a Commit Status of Reliability, and decommit Resources, including Resources with a Commit Status of Self, to alleviate such reliability issues in accordance with its authority as Reliability Coordinator.

An emergency condition may arise within the operating area of a local Transmission Operator that may involve elements not monitored by SPP. Such emergencies may require out of merit commitment, decommitment or dispatch instructions to be issued to one or more Resources to resolve the emergency. Time permitting, the local Transmission Operator shall request SPP to issue such instructions. To the extent time does not permit, the local Transmission Operator may issue such instructions to the Resource in accordance with its authorities as a reliability entity. In such cases, the following shall take place:

(i) If initial instructions are issued by a local Transmission Operator, the Transmission Operator shall notify SPP of the instructions given to the Resource.

(ii) The Transmission Operator and SPP will coordinate to ensure subsequent instructions are provided by SPP.

(iii) SPP shall log such instructions as manual commitment, decommitment or Out-of-Merit Dispatch instruction, as appropriate, as if it gave such instruction to the Resource.

(iv) The Resource shall be eligible to receive the compensation for such instructions whether issued by SPP or the local Transmission Operator in the same manner as if it had been committed by SPP, provided that SPP determines that the Resource was selected in a non-discriminatory manner. For purposes of making such determination, the standards and procedures applicable to Resource selection in the Intra-Day Reliability Unit Commitment process as described in Section 6.1.2.1 of Attachment AE to the Tariff, shall apply. Recovery of such compensation shall be collected locally as described under Section 4.5.9.10.

(v) In the event of a Transmission Operator directive, the Transmission Operator and SPP shall collaborate to provide a report with an after the fact analysis of the event. All such reports shall be made available to the appropriate stakeholder groups for review on a quarterly basis in the month following the end of the quarter in which the event occurred and will be used to determine the best practice for addressing this type of emergency situation in the future.

(e) In the event that the local transmission operator commits a Resource to resolve an issue other than a Local Reliability Issue, the Resource will be compensated in the same
manner as if it had been committed by SPP, provided that SPP determines that the selected Resource was selected in a non-discriminatory manner. For purposes of making such determination, the standards and procedures described in Section 6.1.2.1 of Attachment AE to the Tariff shall apply. Recovery of such compensation shall be collected regionally as described under Section 4.5.9.10.

(f) In the event that SPP commits a Resource at the request of a local transmission operator to resolve an issue other than a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by SPP. Recovery of such compensation shall be collected regionally as described under Section 4.5.9.10.

(g) In the event that SPP commits a Resource at the request of a local transmission operator to resolve a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by SPP. Recovery of such compensation shall be collected locally as described under Section 4.5.9.10.

4.4.1.4 Update Current Operating Plan

Using the results from the Intra-Day RUC analysis, SPP will update the Current Operating Plan and will issue start-up and shut-down orders to Resources other than DVERs and NDVERs for which SPP is calculating an output forecast (these Resources are always assumed to be self-committed if available) as appropriate. SPP may only issue changes to shut-down orders issued as part of the DA Market results or move a DA Market committed combined cycle Resource that has been registered to submit configuration based offers as described under Section 4.2.2.5.3(4) into a lower configuration to address an anticipated excess supply condition as described under Section 4.3.2.2(3)(b) and/or to address any other Emergency conditions. If SPP de-commits an SPP committed Resource or moves a combined cycle Resource into a lower configuration for any hour of the DA Market commitment schedule, and causes that Resource to buy back its Energy and/or Operating Reserve position at RTBM prices that exceed the DA Market prices for the comparable products, that Resource is eligible for compensation under Section 4.5.9.9.

4.4.2.1 Managing Regulation Control Status Prior to Operating Hour

SPP selection of Regulation Qualified Resources, Regulation-Up Qualified Resources and Regulation-Down Qualified Resources to be available to be cleared for Regulation-Up and/or Regulation-Down within the Operating Hour will be performed as follows:

(1) Prior to each Operating Hour, SPP will select sufficient on-line regulation qualified Resources to meet the Regulation-Up and Regulation-Down requirements using the results of the most recently completed RUC analysis in combination with the selection process described under (3) below. Prior to the Operating Hour, in order to prepare for the loss of regulating capability on one or more selected Resources within the Operating Hour and support reliable operations,
SPP will also select, as necessary, additional regulation qualified Resources that have no difference between their regulating limits and economic limits.

(2) No later than 20 minutes prior to the Operating Hour, SPP will notify the affected Market Participants by entering such Resource selections in the Current Operating Plan as being required to regulate in the identified Operating Hour(s);

(a) Market Participants with selected Resources that are physically capable of providing regulation must submit a Resource Control Status = “Regulating” at least ten (10) minutes prior to the Operating Hour to ensure that the Resources will be available to clear Regulation-Up and/or Regulation-Down in the first Dispatch Interval of the upcoming Operating Hour.

(3) SPP will, in order to support reliable operations, update the Current Operating Plan by selecting additional regulation qualified Resources as being required to regulate. Combined cycle Resources modeled as described under Section 4.2.2.5.3(4) are not eligible for regulation selection in any hour in which they are transitioning from one configuration to another. SPP will use the following criteria to select such additional resources in merit order to the extent that such resources can be deployed reliably:

(a) Regulation qualified Resources with the lowest submitted Offer for Regulation-Up and/or Regulation-Down (as applicable) that are currently being dispatched for Energy at a level less than the Resource’s regulation maximum limit and/or greater than that Resource’s regulation minimum limit; and

(b) Regulation-Up Qualified Resources will be selected based upon the sum of each Resource’s estimated lost opportunity cost for Energy output between regulation maximum limit and economic maximum limit and that Resources Regulation-Up Offer; and

(c) Regulation-Down Qualified Resources will be selected based upon the sum of each Resource’s estimated lost opportunity cost for Energy output between regulation minimum limit and economic minimum limit and that Resources Regulation-Down Offer.

4.5.8.12 Day-Ahead Make-Whole-Payment Amount

(1) The Day-Ahead Make-Whole-Payment Amount is a credit or charge\(^2\) to a Resource Asset Owner and is calculated for each Resource with an associated DA Market Commitment Period that was committed by SPP with a Day-Ahead Market Resource Offer Commitment Status of “Market” or “Reliability” as defined under Section 4.2.2.2.1, or was committed as part of the Multi-Day Reliability Assessment as defined under Section 4.2.6.3\(^{[MCRR25.18]}\). A payment is made to the Resource Asset Owner when the sum of the Resource’s DA Market Start-Up Offer costs, No-Load

\(^2\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
Offer costs, Transition State Offer costs, Energy Offer Curve and Operating Reserve Offer costs associated with cleared DA Market amounts for Energy and Operating Reserve is greater than the Energy and Operating Reserve DA Market revenues received for that Resource over the Resource’s DA Market Make-Whole-Payment Eligibility Period.

(2) A Resource’s DA Market Make-Whole-Payment Eligibility Period is equal to a Resource’s DA Market Commitment Period except as defined below:

(a) For Resources with an associated DA Market Commitment Period that begins in one Operating Day and ends in the next Operating Day, two DA Market Make-Whole-Payment Eligibility Periods are created. The first period begins in the first Operating Day in the hour that the DA Market Commitment Period begins and ends in the last hour of the first Operating Day. The second period begins in the first hour of the next Operating Day and ends in the last hour of the DA Market Commitment Period.

(3) The following cost recovery eligible rules apply to each DA Market Make-Whole-Payment Eligibility Period. Offer costs are calculated using the DA Market Offer prices in effect at the time the commitment decision was made except under the situation described under Section (b).a.i below.

(a) There may be more than one DA Market Make-Whole Payment Eligibility Period for a Resource in a single Operating Day for which a credit or charge is calculated. A single DA Market Make-Whole Payment Eligibility Period is contained within a single Operating Day.

(b) A Resource’s DA Market Start-Up Offer costs are not eligible for recovery in the following DA Market Make-Whole Payment Eligibility Periods:

(a) Any DA Market Make-Whole Payment Eligibility Period that is adjacent to the end of a RUC Make-Whole Payment Eligibility Period except as described in (i) below;

(ii)(i) As described under Section 4.5.9.8(3)h, to the extent that the full amount of the RTBM Start-Up Offer is not accounted for in the adjacent RUC Make-Whole Payment Eligibility Period, any remaining RTBM Start-Up Offer costs are carried forward for recovery in the adjacent Day-Ahead Make-Whole Payment Eligibility Period.

(b) Any DA Market Make-Whole Payment Eligibility Period resulting from a DA Market Commitment Period that contains a DA Market Self-Commit Hour; and

(c) Any DA Make-Whole Payment Eligibility Period for which a Resource is a Synchronized Resource prior to this commitment period at a time one hour prior to that Resource’s DA Market Commit Time less the Resource’s Sync-To-Min Time.

(c) For each DA Market Make-Whole Payment Eligibility Period within an Operating Day, a Resource’s DA Market Start-Up Offer is divided by the lesser of (1) the Resource’s Minimum Run Time rounded down to the nearest hour or (2) 24 Hours, and that portion of
the Start-Up Offer is included as a cost in each hour of the DA Market Make-Whole Payment Eligibility Period until the sum of these hourly costs are equal to the DA Market Start-Up Offer or until the end of the DA Market Make-Whole Payment Eligibility Period, whichever occurs first.

(d) To the extent that the full amount of the DA Market Start-Up Offer is not accounted for in the last DA Market Make-Whole Payment Eligibility Period in the Operating Day, any remaining DA Market Start-Up Offer costs are carried forward for recovery in the first DA Market Make-Whole Payment Eligibility Period of the following Operating Day. For example, consider a Resource that is committed starting at 10:00 PM in Operating Day 1 that has a Minimum Run Time of 10 hours and a Start-Up Offer of $10,000. The DA Market Commitment Period is from 10:00 PM in Operating Day 1 through 8:00 AM of Operating Day 2. For DA Market Make-Whole Payment calculation purposes, the DA Market Commitment Period is split into two separate DA Market Make-Whole Payment Eligibility Periods as described in (2).b above. The first DA Market Make-Whole Payment Eligibility Period will include $1000/hour of Start-Up Offer costs ($10,000 / 10 Hours) in hours 23 and 24. The second DA Market Make-Whole Payment Eligibility Period will include $1000/hour of Start-Up Offer costs in hours 1 through 8.

(e) If the Resource is a combined cycle Resource, additional costs associated with situations in which the Resource has cleared Operating Reserve in the Day-Ahead Market and must buy back that position in Real-Time at an average Real-Time MCP that is greater than the Day-Ahead MCP, the Market Participant may be eligible for a make-whole payment. To be eligible, these costs must be incurred during a time period in which the Resource is transitioning between configurations, at the direction of SPP, such cost is not due to any independent action of the Market Participant and such cost is not incurred during a RUC Make-Whole Payment Eligibility Period. In such cases, the additional costs are equal to the difference between the Real-Time MCP and the Day-Ahead MCP multiplied by the Day-Ahead Market cleared Operating Reserve MW amounts. Recovery of these costs is limited to the time period defined as the Transition State Time submitted in the Resource Offer.

(4) The amount to each Asset Owner (AO) for each eligible Resource Settlement Location for each hour in a given DA Market Make-Whole Payment Eligibility Period is calculated as follows:

\[
\text{DaMwpCpAmt}_{a,s,c} = \max \left( 0, \sum_{h} \left( \text{DaMwpCostHrlyAmt}_{a,h,s,c} + \text{DaMwpRevHrlyAmt}_{a,h,s,c} \right) \right) \times (-1)
\]

(a) \text{DaMwpCostHrlyAmt}_{a,h,s,c} =
DaStartUpEligHrlyFlg \(_{a, h, s, c}\) * DaStartUpHrlyAmt \(_{a, h, s, c}\) 

+ DaClrdComStatHrlyFlg \(_{h, s, c}\) 

* [ DaRucRmndrStartUpHrlyAmt \(_{a, s, h, c}\) + DaTransitionHrlyAmt \(_{a, s, h, c}\) 

+ DaCcSpinAdjHrlyAmt \(_{a, s, h}\) + DaCcSuppAdjHrlyAmt \(_{a, s, h}\) 

+ DaNoLoadHrlyAmt \(_{a, h, s, c}\) + DaIncrEnHrlyAmt \(_{a, h, s, c}\) 

+ DaRegUpAvailHrlyAmt \(_{a, h, s, c}\) + DaRegDnAvailHrlyAmt \(_{a, h, s, c}\) 

+ DaSpinAvailHrlyAmt \(_{a, h, s, c}\) + DaSuppAvailHrlyAmt \(_{a, h, s, c}\) ] 

Where,

\[
\#\text{DaIncrEnHrlyAmt} \(_{a, h, s, c}\) = \int_0^{\text{ABS(DaClrdHrlyQty} \(_{a, h, s}\) )} \text{DA Market Energy Offer Curve}
\]

(a.1) IF RtTransitStateFlg \(_{a, s, i} = 1\) THEN 

\[
\text{DaCcSpinAdj5minAmt} \(_{a, s, i}\) = \\
\text{IF (RtRucComStat5minFlg } \(_{a, s, i} >= 0, \text{THEN 0, ELSE 1 }) \\
\star (\text{DaSpinHrlyAmt} \(_{a, s, h}/12 + \text{RtSpin5minAmt} \(_{a, s, i}\) )
\]

ELSE 

\[
\text{DaCcSpin5minAmt} \(_{a, s, h} = 0\)
\]

(a.1.1) \text{DaCcSpinAdjHrlyAmt} \(_{a, s, h} = \

\text{Max ( 0, } \sum_{i} \text{DaCcSpinAdj5minAmt} \(_{a, s, i})
\]

(a.2) IF RtTransitStateFlg \(_{a, s, i} = 1\) THEN
\[
\text{DaCcSuppAdj5minAmt}_{a,s,i} =
\]

\[
\text{IF} \ (\text{RtRucComStat5minFlg}_{a,s,i} \geq 0, \ \text{THEN} \ 0, \ \text{ELSE} \ 1 )
\]

\[
\times (\text{DaSuppHrlyAmt}_{a,s,h} / 12 + \text{RtSupp5minAmt}_{a,s,i})
\]

\[
\text{ELSE}
\]

\[
\text{DaCcSupp5minAmt}_{a,s,h} = 0
\]

(a.2.1) \[
\text{DaCcSuppAdjHrlyAmt}_{a,s,h} =
\]

\[
\text{Max} \ (0, \sum_{i} \text{DaCcSuppAdj5minAmt}_{a,s,i})
\]

(b) \[
\text{DaMwpRevHrlyAmt}_{a,h,s,c} = \text{DaClrdComStatHrlyFlg}_{h,s,c}
\]

\[
\times [( \text{DaLmpHrlyPrc}_{s,h} \times \text{DaClrdHrlyQty}_{a,s,h} )
\]

\[
+ \text{DaRegUpHrlyAmt}_{a,h,s} + \text{DaRegDnHrlyAmt}_{a,h,s}
\]

\[
+ \text{DaSpinHrlyAmt}_{a,h,s} + \text{DaSuppHrlyAmt}_{a,h,s}
\]

(5) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[
\text{DaMwpDlyAmt}_{a,s,d} = \sum_{c} \text{DaMwpCpAmt}_{a,s,c}
\]

(6) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{DaMwpAoAmt}_{a,m,d} = \sum_{s} \text{DaMwpDlyAmt}_{a,s,d}
\]

(7) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{DaMwpMpAmt}_{m,d} = \sum_{a} \text{DaMwpAoAmt}_{a,m,d}
\]
(8) For FERC Electric Quarterly Reporting (EQR) purposes, SPP calculates DA Market Make-Whole Payment $ per DA Market Make-Whole-Payment Eligibility Period for each Asset Owner as follows:

(a) \[ \text{EqrDaMwpHrlyPre} \ a, s, c = (-1) \times \text{DaMwpCpAmt} \ a, s, c \]

(b) IF \[ \text{EqrDaMwpHrlyPre} \ a, s, c > 0 \]
THEN
\[ \text{EqrDaMwpHrlyQty} \ a, s, c = 1 \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaMwpCpAmt_{a,s,c}</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Day-Ahead Make-Whole-Payment Amount per AO per Settlement Location per DA Market Make-Whole-Payment Eligibility Period - The DA Market make-whole amount to AO a for DA Market Make-Whole-Payment Eligibility Period c at Resource Settlement Location s.</td>
</tr>
<tr>
<td>DaStartUpHrlyAmt_{a,h,s,c}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Start-Up Cost Amount per AO per Settlement Location per Hour Per DA Market Make-Whole-Payment Eligibility Period - The DA Market Start-Up Offer associated with AO a’s eligible Resource at Settlement Location s for DA Market Make-Whole-Payment Eligibility Period c that is included in each Hour h of the DA Market Make-Whole-Payment Eligibility Period. This value is calculated by dividing DaStartUpAmt_{a,s,c} by the lesser of the Resource’s DaMinRunTime_{a,h,s,c} or 24. These hourly values are carried forward into the following Operating Day, if needed, to ensure recovery of any remaining DaStartUpAmt_{a,s,c}.</td>
</tr>
<tr>
<td>DaStartUpAmt_{a,s,c} (Not Available on Settlement Statement)</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Day-Ahead Start-Up Cost Amount per AO per Settlement Location per DA Market Make-Whole-Payment Eligibility Period - The DA Market Start-Up Offer associated with AO a’s eligible Resource at Settlement Location s for DA Market Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>DaStartUpEligHrlyFlg_{a,h,s,c}</td>
<td>None</td>
<td>Hour</td>
<td>Day-Ahead Start-Up Recovery Eligibility Flag per Resource Settlement Location per DA Market Make-Whole-Payment Eligibility Period – This flag is set equal to 1 in each hour of a DA Market Make-Whole-Payment Eligibility Period where the Resource is eligible to recover start-up costs, or 0 in each hour of the DA Market Make-Whole-Payment Eligibility Period where the Resource is not eligible to recover start-up costs.</td>
</tr>
<tr>
<td>DaClrdComStatHrlyFlg_{h,s,c}</td>
<td>None</td>
<td>Hour</td>
<td>Day-Ahead Commitment Status Hourly Flag per Resource Settlement Location per DA Market Make-Whole-Payment Eligibility Period – This flag is set equal to 1 for each hour of a DA Market Make-Whole-Payment Eligibility Period in which its Commitment Status was “Market” or “Reliability, or 0 if its Commitment Status was “Self”.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
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<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaRucRmndrStartUpHrlyAmt_{a,s,h,c}</td>
<td>$</td>
<td>Hour</td>
<td><strong>Day-Ahead RUC Remaining Start-Up Offer Amount per Hour per DA Market Make-Whole Payment Eligibility Period</strong> - the amount of Start-Up Offer recovery remaining associated with an adjacent RUC Make-Whole Payment Eligibility Period.</td>
</tr>
<tr>
<td>DaTransitionHrlyAmt_{a,s,h,c}</td>
<td>$</td>
<td>Eligibility Period</td>
<td><strong>Day-Ahead Transition Cost Amount per AO per Settlement Location per Hour in DA Market Make-Whole-Payment Eligibility Period</strong> - The DA Market Transition State Offer associated with AO a's eligible combined cycle Resource at Settlement Location s in Hour h of DA Market Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>DaCcSpinAdjHrlyAmt_{a,s,h}</td>
<td>$</td>
<td>Hour</td>
<td><strong>Day-Ahead Combined Cycle Spinning Reserve Cost Adjustment per AO per Settlement Location per Hour</strong> – the additional cost incurred by AO a at Combined Cycle Settlement Location s associated with the buying back of Day-Ahead Market Spinning Reserve position during transitions between configurations for Hour h.</td>
</tr>
<tr>
<td>DaCcSuppAdjHrlyAmt_{a,s,h}</td>
<td>$</td>
<td>Hour</td>
<td><strong>Day-Ahead Combined Cycle Supplemental Reserve Cost Adjustment per AO per Settlement Location per Hour</strong> – the additional cost incurred by AO a at Combined Cycle Settlement Location s associated with the buying back of Day-Ahead Market Supplemental Reserve position during transitions between configurations for Hour h.</td>
</tr>
<tr>
<td>DaCcSpinAdj5minAmt_{a,s,i}</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Day-Ahead Combined Cycle Spinning Reserve Cost Adjustment per AO per Settlement Location per Dispatch Interval</strong> – the additional cost incurred by AO a at Combined Cycle Settlement Location s associated with the buying back of Day-Ahead Market Spinning Reserve position during transitions between configurations for Dispatch Interval i.</td>
</tr>
<tr>
<td>DaCcSuppAdj5minAmt_{a,s,i}</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Day-Ahead Combined Cycle Supplemental Reserve Cost Adjustment per AO per Settlement Location per Dispatch Interval</strong> – the additional cost incurred by AO a at Combined Cycle Settlement Location s associated with the buying back of Day-Ahead Market Supplemental Reserve position during transitions between configurations for Dispatch Interval i.</td>
</tr>
</tbody>
</table>

Day-Ahead RUC Remaining Start-Up Offer Amount per Hour per DA Market Make-Whole Payment Eligibility Period - the amount of Start-Up Offer recovery remaining associated with an adjacent RUC Make-Whole Payment Eligibility Period.

Day-Ahead Transition Cost Amount per AO per Settlement Location per Hour in DA Market Make-Whole-Payment Eligibility Period - The DA Market Transition State Offer associated with AO a’s eligible combined cycle Resource at Settlement Location s in Hour h of DA Market Make-Whole-Payment Eligibility Period c.

Day-Ahead Combined Cycle Spinning Reserve Cost Adjustment per AO per Settlement Location per Hour – the additional cost incurred by AO a at Combined Cycle Settlement Location s associated with the buying back of Day-Ahead Market Spinning Reserve position during transitions between configurations for Hour h.

Day-Ahead Combined Cycle Supplemental Reserve Cost Adjustment per AO per Settlement Location per Hour – the additional cost incurred by AO a at Combined Cycle Settlement Location s associated with the buying back of Day-Ahead Market Supplemental Reserve position during transitions between configurations for Hour h.

Day-Ahead Combined Cycle Spinning Reserve Cost Adjustment per AO per Settlement Location per Dispatch Interval – the additional cost incurred by AO a at Combined Cycle Settlement Location s associated with the buying back of Day-Ahead Market Spinning Reserve position during transitions between configurations for Dispatch Interval i.

Day-Ahead Combined Cycle Supplemental Reserve Cost Adjustment per AO per Settlement Location per Dispatch Interval – the additional cost incurred by AO a at Combined Cycle Settlement Location s associated with the buying back of Day-Ahead Market Supplemental Reserve position during transitions between configurations for Dispatch Interval i.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtTransistionStateFlg&lt;sub&gt;a,b,i&lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Real-Time Transition State Flag per AO per Settlement Location in DA Make-Whole-Payment Eligibility Period – The value defined under Section 4.5.9.8.</td>
</tr>
<tr>
<td>RtRucComStat5minFlg&lt;sub&gt;a,s,i,c&lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>RUC Commitment Status Flag per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period — The value defined under Section 4.5.9.8.</td>
</tr>
<tr>
<td>DaMinRunTime&lt;sub&gt;a,h,s,c&lt;/sub&gt; (Not Available on Settlement Statement)</td>
<td>Time</td>
<td>Hour</td>
<td>Day-Ahead Minimum Run Time per AO per Settlement Location Per Hour – The Minimum Run Time associated with AO a’s eligible Resource at Settlement Location s for DA Market Make-Whole-Payment Eligibility Period c as submitted as part of the DA Market Offer.</td>
</tr>
<tr>
<td>DaMwpCostHrlyAmt&lt;sub&gt;a,h,s,c&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Make-Whole Payment Cost Amount per AO per Settlement Location per Hour in the DA Market Make-Whole-Payment Eligibility Period - The hourly cost associated with AO a’s eligible Resource at Settlement Location s for Hour h in DA Market Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>DaMwpRevHrlyAmt&lt;sub&gt;a,h,s,c&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Make-Whole Payment Revenue Amount per AO per Settlement Location per Hour in the DA Market Make-Whole-Payment Eligibility Period – The hourly revenue associated with AO a’s eligible Resource at Settlement Location s for Hour h in DA Market Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>DaNoLoadHrlyAmt&lt;sub&gt;a,h,s,c&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead No-Load Cost Amount per AO per Settlement Location per Hour per DA Market Make-Whole-Payment Eligibility Period - The No-Load Offer, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Hour h in DA Market Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>DaIncrEnHrlyAmt&lt;sub&gt;a,h,s,c&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Incremental Energy Cost Amount per AO per Settlement Location per Hour in the DA Market Make-Whole-Payment Eligibility Period - The average incremental energy offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Hour h in DA Market Make-Whole-Payment Eligibility Period c at an output level equal to DaClrdHrlyQty&lt;sub&gt;a,s,h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaRegUpAvailHrlyAmt &lt;sub&gt;a, h, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td><strong>Day-Ahead Regulation-Up Offer Cost Amount per AO per Settlement Location per Hour per DA Market Make-Whole-Payment Eligibility Period</strong> - The Regulation-Up Offer cost, in dollars, associated with AO &lt;sup&gt;a&lt;/sup&gt;’s eligible Resource at Settlement Location &lt;sup&gt;s&lt;/sup&gt; for Hour &lt;sup&gt;h&lt;/sup&gt; in DA Market Make-Whole-Payment Eligibility Period &lt;sup&gt;c&lt;/sup&gt;. The Resource’s Regulation-Up Offer cost in the Hour is equal to the Resources <strong>DaRegUpHrlyQty &lt;sub&gt;a, z, s, h&lt;/sub&gt;</strong> multiplied by the Resource’s Regulation-Up Offer, in $/MW.</td>
</tr>
<tr>
<td>DaRegDnAvailHrlyAmt &lt;sub&gt;a, h, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td><strong>Day-Ahead Regulation-Down Offer Cost Amount per AO per Settlement Location per Hour per DA Market Make-Whole-Payment Eligibility Period</strong> - The Regulation-Down Offer cost, in dollars, associated with AO &lt;sup&gt;a&lt;/sup&gt;’s eligible Resource at Settlement Location &lt;sup&gt;s&lt;/sup&gt; for Hour &lt;sup&gt;h&lt;/sup&gt; in DA Market Make-Whole-Payment Eligibility Period &lt;sup&gt;c&lt;/sup&gt;. The Resource’s Regulation-Down Offer cost in the Hour is equal to the Resources <strong>DaRegDnHrlyQty &lt;sub&gt;a, z, s, h&lt;/sub&gt;</strong>, multiplied by the Resource’s Regulation-Down Offer, in $/MW.</td>
</tr>
<tr>
<td>DaSpinAvailHrlyAmt &lt;sub&gt;a, h, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td><strong>Day-Ahead Spin Offer Cost Amount per AO per Settlement Location per Hour per DA Market Make-Whole-Payment Eligibility Period</strong> - The Spinning Reserve Offer cost, in dollars, associated with AO &lt;sup&gt;a&lt;/sup&gt;’s eligible Resource at Settlement Location &lt;sup&gt;s&lt;/sup&gt; for Hour &lt;sup&gt;h&lt;/sup&gt; in DA Market Make-Whole-Payment Eligibility Period &lt;sup&gt;c&lt;/sup&gt;. The Resource’s Spinning Reserve Offer cost in the Hour is equal to the Resources <strong>DaSpinHrlyQty &lt;sub&gt;a, z, s, h&lt;/sub&gt;</strong> multiplied by the Resource’s Spinning Reserve Offer, in $/MW.</td>
</tr>
<tr>
<td>DaSuppAvailHrlyAmt &lt;sub&gt;a, h, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td><strong>Day-Ahead Supplemental Offer Cost Amount per AO per Settlement Location per Hour per DA Market Make-Whole-Payment Eligibility Period</strong> - The Supplemental Reserve Offer cost, in dollars, associated with AO &lt;sup&gt;a&lt;/sup&gt;’s eligible Resource at Settlement Location &lt;sup&gt;s&lt;/sup&gt; for Hour &lt;sup&gt;h&lt;/sup&gt; in DA Market Make-Whole-Payment Eligibility Period &lt;sup&gt;c&lt;/sup&gt;. The Resource’s Supplemental Reserve Offer cost in the Hour is equal to the Resources <strong>DaSuppHrlyQty &lt;sub&gt;a, z, s, h&lt;/sub&gt;</strong> multiplied by the Resource’s Supplemental Reserve Offer, in $/MW.</td>
</tr>
<tr>
<td>DaLmpHrlyPrc &lt;sub&gt;s, h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td><strong>Day-Ahead LMP</strong> - The DA Market LMP at Resource Settlement Location &lt;sup&gt;s&lt;/sup&gt; for Hour &lt;sup&gt;h&lt;/sup&gt;.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>---------------------------------</td>
<td>-------</td>
<td>---------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaClrdHrlyQty_{a, s, h}</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Resource Settlement Location per Hour – The value described under Section 4.5.8.1 for AO a’s eligible Resource Settlement Location s.</td>
</tr>
<tr>
<td>DaRegUpHrlyAmt_{a, h, s}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Amount per AO per Settlement Location per Hour – The DaRegUpHrlyAmt_{a, s, h}, calculated under Section 4.5.8.4 associated with AO a’s eligible Resource at Settlement Location s for Hour h.</td>
</tr>
<tr>
<td>DaRegDnHrlyAmt_{a, h, s}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Amount per AO per Settlement Location per Hour – The DaRegDnHrlyAmt_{a, s, h}, calculated under Section 4.5.8.5 associated with AO a’s eligible Resource at Settlement Location s for Hour h.</td>
</tr>
<tr>
<td>DaSpinHrlyAmt_{a, h, s}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Amount per AO per Settlement Location per Hour – The DaSpinHrlyAmt_{a, s, h}, calculated under Section 4.5.8.6 associated with AO a’s eligible Resource at Settlement Location s for Hour h.</td>
</tr>
<tr>
<td>DaSuppHrlyAmt_{a, h, s}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Amount per AO per Settlement Location per Hour – The DaSuppHrlyAmt_{a, s, h}, calculated under Section 4.5.8.7 associated with AO a’s eligible Resource at Settlement Location s for Hour h.</td>
</tr>
<tr>
<td>DaMwpDlyAmt_{a, s, d}</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Amount per AO per Settlement Location per Operating Day – The DA Market make-whole amount to AO a for Operating Day d at Resource Settlement Location s.</td>
</tr>
<tr>
<td>DaMwpAoAmt_{a, m, d}</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Amount per AO per Operating Day – The DA Market make-whole amount to AO a associated with Market Participant m for Operating Day d.</td>
</tr>
<tr>
<td>DaMwpMpAmt_{m, d}</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Amount per MP per Operating Day – The DA Market make-whole amount to Market Participant m for Operating Day d.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------</td>
<td>------</td>
<td>-----------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>EqrDaMwpHrlyPre&lt;sub&gt;a,s,c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td><em>Day-Ahead Electric Quarterly Reporting Make-Whole-Payment Amount per AO per Settlement Location per DA Market Make-Whole-Payment Eligibility Period</em> - The DA Market make-whole amount to AO &lt;i&gt;a&lt;/i&gt; for DA Market Make-Whole-Payment Eligibility Period &lt;i&gt;c&lt;/i&gt; at Resource Settlement Location &lt;i&gt;s&lt;/i&gt; for use by AO &lt;i&gt;a&lt;/i&gt; in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrDaMwpHrlyQty&lt;sub&gt;a,s,c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td><em>Day-Ahead Electric Quarterly Reporting Make-Whole-Payment Quantity per AO per Settlement Location per DA Market Make-Whole-Payment Eligibility Period</em> – This value is set equal to 1 if EqrDaMwpHrlyPre&lt;sub&gt;a,s,c&lt;/sub&gt; &gt; 0 for use by AO &lt;i&gt;a&lt;/i&gt; in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
</tbody>
</table>

**<i>a</i>**
- None
- An Asset Owner.

**<i>h</i>**
- None
- An Hour in a DA Market Make-Whole-Payment Eligibility Period.

**<i>s</i>**
- None
- A Resource Settlement Location.

**<i>c</i>**
- None
- A DA Market Make-Whole-Payment Eligibility Period.

**<i>d</i>**
- None
- An Operating Day.

**<i>m</i>**
- None
- A Market Participant.
4.5.9 Real-Time Balancing Market Settlement

Settlement calculations for the Real-Time Balancing Market are performed on a Dispatch Interval basis for each Operating Day and are based upon the difference between the results of the RTBM process and the DA Market clearing for that Operating Day. To calculate RTBM actual Energy in a Dispatch Interval for Asset Owners that have not directly submitted 5-minute interval meter data, SPP allocates the submitted hourly meter data for Resources and loads into 5-minute values using 5-minute telemetered or State Estimator profiles for the corresponding hour. The profiling of the hourly meter data maintains the shape of the 5-minute telemetered or State Estimator values even if there are both positive and negative values contained within the 12 intervals. All Dispatch Interval values are expressed in MW, not MWh. Exhibit 4-19 shows an example of how the profiling will work for a Resource that submits an actual hourly meter amount of -80 MWh.

Exhibit 4-2: Meter Profiling Example

<table>
<thead>
<tr>
<th>Interval</th>
<th>(1) State Estimator MW</th>
<th>(2) Absolute Value of Column (1)</th>
<th>(3) Normalize Column (2) [Col (2) MW / Total Col (2) MW]</th>
<th>(4) Profiled Hourly Meter (-80 – (-66.25)) * 12 * Col (3) + Col (1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>10</td>
<td>10</td>
<td>0.012</td>
<td>8</td>
</tr>
<tr>
<td>2</td>
<td>5</td>
<td>5</td>
<td>0.006</td>
<td>4</td>
</tr>
<tr>
<td>3</td>
<td>0</td>
<td>0</td>
<td>0.000</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>-50</td>
<td>50</td>
<td>0.061</td>
<td>-60</td>
</tr>
<tr>
<td>5</td>
<td>-60</td>
<td>60</td>
<td>0.073</td>
<td>-72</td>
</tr>
<tr>
<td>6</td>
<td>-70</td>
<td>70</td>
<td>0.085</td>
<td>-84</td>
</tr>
<tr>
<td>7</td>
<td>-80</td>
<td>80</td>
<td>0.097</td>
<td>-96</td>
</tr>
<tr>
<td>8</td>
<td>-90</td>
<td>90</td>
<td>0.109</td>
<td>-108</td>
</tr>
<tr>
<td>9</td>
<td>-100</td>
<td>100</td>
<td>0.121</td>
<td>-120</td>
</tr>
<tr>
<td>10</td>
<td>-110</td>
<td>110</td>
<td>0.133</td>
<td>-132</td>
</tr>
<tr>
<td>11</td>
<td>-120</td>
<td>120</td>
<td>0.145</td>
<td>-144</td>
</tr>
<tr>
<td>12</td>
<td>-130</td>
<td>130</td>
<td>0.158</td>
<td>-156</td>
</tr>
<tr>
<td></td>
<td>-66.25 MWh</td>
<td>825 (total)</td>
<td>1.000</td>
<td>-80 MWh (Meter) (submitted)</td>
</tr>
</tbody>
</table>

RTBM results are presented on an hourly basis but Market Participants and Asset Owners have access to the 5 minute data for verification purposes.

(1) Each Market Participant with actual Resource output is charged or paid for each Settlement Location for the difference between the amount of actual RTBM physical Energy sold and the amount of physical Energy sold in the DA Market, net of Bilateral Settlement Schedules for Energy, at the associated RTBM LMP (see Section 4.5.9.1);
(2) Each Market Participant with Import Interchange Transactions or Through Interchange Transactions (Resource Node) is charged or paid for each Settlement Location for the difference between the amount of actual RTBM physical import Energy scheduled and the amount of physical Energy sold in the DA Market, net of Bilateral Settlement Schedules for Energy, at the associated RTBM LMP (see Section 4.5.9.2);

(3) Each Market Participant with virtual Energy purchased in the DA Market is paid for the amount of virtual Energy purchased in the DA Market at the associated RTBM LMP (see Section 4.5.9.3);

(4) Each Market Participant with cleared Operating Reserve Offers is charged or paid for each Settlement Location:

   (a) For the difference between the amount of Regulation-Up sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Regulation-Up MCP (see Section 4.5.9.4);

   (b) For the difference between the amount of Regulation-Down sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Regulation-Down MCP (see Section 4.5.9.5);

   (c) For the difference between the amount of Spinning Reserve sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Spinning Reserve MCP (see Section 4.5.9.6); and

   (d) For the difference between the amount of Supplemental Reserve sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Supplemental Reserve MCP (see Section 4.5.9.7).

(5) Each Market Participant with actual load consumption is charged or paid for each Settlement Location for the difference between the amount of actual physical load purchased and the amount of physical Energy purchased in the DA Market, net of Bilateral Settlement Schedules for Energy, at the associated RTBM LMP (see Section 4.5.9.1);

(6) Each Market Participant with Export Interchange Transactions or Through Interchange Transactions (Load Node) is charged or paid for each Settlement Location for the difference between the amount of actual physical export Energy scheduled and the amount of physical export Energy purchased in the DA Market, net of Bilateral Settlement Schedules for Energy, at the associated RTBM LMP (see Section 4.5.9.2);

(7) Market Participants with SPP committed Resources in any of the RUC processes that were not committed in the DA Market and combined cycle Resources that were committed in the DA Market and committed by SPP into a higher configuration as part of the RUC processes may receive a make whole-payment if the total revenues received for Energy and Operating Reserve

sales in the RTBM settlement are less than the Resource’s Offer costs. See Section 4.5.9.8 for calculation details. Certain costs are not eligible for recovery as follows:

(a) If the Resource operates outside of its Operating Tolerance in a Dispatch Interval, costs associated with Energy provided in excess of the Resource’s Desired Dispatch are not eligible for recovery in that Dispatch Interval;

(b) If Resource is in “Manual” Control Status in a Dispatch Interval, costs associated with Energy provided in excess of the Resource’s Desired Dispatch are not eligible for recovery in that Dispatch Interval; and

(c) If the Resource increases its minimum limits in a Dispatch Interval above the minimum limits used by SPP to make the commitment decision by more than the Resource’s Operating Tolerance, costs associated with Energy provided in excess of the Resource’s Desired Dispatch are not eligible for recovery in that Dispatch Interval.

(8) Make-Whole payments for SPP committed Resources as described in (7) above are collected on a daily basis from Market Participants based upon their pro-rata share of the sum of following quantities for the Operating Day as described in detail under Section 4.5.9.10:

(a) The absolute value of the net Settlement Location deviations from DA Market cleared amounts for load, virtual transactions and interchange transactions – excluding deviations resulting from actual load consumption that is less than DA Market cleared load MWh during capacity shortage condition Emergencies;

(b) The positive difference between RTBM Resource minimum limits and DA Market Resource minimum limits, subject to exclusion if certain criteria are met;

(c) The positive difference between the DA Market Resource maximum limits and the RTBM Resource maximum limits, subject to exclusion if certain criteria are met;

(d) A Resource’s DA Market cleared amount if that Resource is off-line in the RTBM, subject to exclusion if certain criteria are met;

(e) The absolute value of the difference between a Resource’s actual output and the Resource’s Desired Dispatch quantity if Resource is in “Manual” Control Status;

(f) The actual Resource output for Resources that self-committed following the close of the DA Market, subject to exclusion if certain criteria are met;

(g) A Resource’s Desired Dispatch quantity for Resources that were committed following the close of the DA Market if that Resource is off-line in the RTBM, subject to exclusion if certain criteria are met; and

(h) The absolute value of a Resource’s Uninstructed Resource Deviation if that Resource operated outside of its Operating Tolerance, subject to exclusion if certain criteria are met.
(9) In addition, Resources may receive a make-whole payment related to a Manual Dispatch Instruction as described under Section 4.5.9.9, subject to certain eligibility requirements, as follows:

(a) If the Resource is issued a Manual Dispatch Instruction by SPP in any hour that creates Out Of Merit Energy (OOME) in excess of the Resource’s Dispatch Instruction and the Resource Offer costs associated with the OOME are greater than the Energy revenue received for the OOME, the Resource will receive the difference between the Energy Offer Curve costs associated with the OOME and the OOME Energy revenue;

(b) If the Manual Dispatch Instruction is for Energy in the down direction and the RTBM LMP is greater than the DA Market LMP, the Asset Owner will receive a credit for the difference multiplied by the OOME MW. The OOME MW is calculated as Max (0, the difference between the Resource’s DA Market cleared Energy MW and actual Resource output); and

(c) If during the Manual Dispatch Instruction, the RTBM cleared amount of an Operating Reserve product is less than the DA Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the DA Market MCP, the Asset Owner will receive a credit for the difference multiplied by the OOMOR MW. The OOMOR MW is calculated as Max (0, the difference between the Resource’s DA Market cleared Operating Reserve MW and the Resource’s RTBM cleared Operating Reserve MW).

Make-whole payments associated with OOME are collected as part of revenue neutrality uplift as described under Section 4.5.12.

(10) Charges for failure to deploy Regulation-Up or Regulation-Down and charges for failure to deploy the specified amount of cleared Spinning Reserve or Supplemental Reserve are collected from Market Participants as part of the RTBM settlement as described under Sections 4.5.9.15 and 4.5.9.17 are distributed to Market Participants on a load ratio share basis as described under Sections 4.5.9.16 and 4.5.9.18;

(11) Charges to Market Participants for RTBM Operating Reserve procurement costs are collected on a Real-Time load ratio share basis as described under Sections 4.5.9.11, 4.5.9.12, 4.5.9.13 and 4.5.9.14;

(12) Resources providing Regulation-Up and/or Regulation-Down deployment will receive a credit or charge associated with the regulation deployment energy as described under Section 4.5.9.19 such that Resources maintain Energy margins that are equal to the Energy margins that would have been attained absent the regulation deployment;
(a) For Regulation-Up, a credit is calculated if the cost rate of the Regulation-Up Energy is greater than the associated LMP and a charge is calculated if the associated LMP is greater the Regulation-Up Energy cost rate;\(^3\)

(b) For Regulation-Down, a credit is calculated if the associated LMP is greater than cost rate of the Regulation-Down Energy and a charge is calculated if the cost rate of the Regulation-Down Energy is greater than the associated LMP.\(^4\)

13 Settlement associated with revenue mismatch due to the impact of marginal losses on the RTBM LMPs is also performed as part of the RTBM settlement as follows. See Section 4.5.9.20 for calculation details;

(a) For each Asset Owner, a proxy loss charge contribution amount is developed for each Settlement Location with a net RTBM withdrawal (RTBM actual – DA Market cleared amount) that is equal to the positive difference between the MLC at the net withdrawal Settlement Location and the weighted average MLC of all net injections (RTBM actual – DA Market cleared amount) assumed to be serving the net withdrawal, multiplied by that Asset Owner’s share of the net withdrawal, where that share is calculated excluding cleared Virtual Bids and cleared Virtual Offers;

(i) The net injections assumed to be serving the net withdrawal are the net injections at the Settlement Locations included in that Asset Owner’s Loss Pool. The Asset Owner’s Loss Pool is defined dynamically and includes all Settlement Locations at which that Asset Owner has transactional activity (Bilateral Settlement Schedules, Resource output, load consumption, Interchange Transactions), but excludes virtual transactions. To the extent that the net injections in the Asset Owner’s Loss Pool are not sufficient to serve the net withdrawals in the Asset Owner’s Loss Pool, net injections from an injection exchange are included to make up the difference. To the extent that the net injections in the Asset Owner’s Loss Pool are greater than the net withdrawals in the Asset Owner’s Loss Pool, the excess is added to the injection exchange;

(ii) The injection exchange is comprised of quantities from Loss Pools in which injection exceeds withdrawal. A weighted average of the MLC at the source of these quantities establishes a reference for the component of the loss charge contributions at Settlement Locations with net withdrawal met from outside the Asset Owner’s Loss Pool.

(b) Each Asset Owner’s credit or charge (all Asset Owner net withdrawals at Settlement Location participate) associated with RTBM over collected losses (which may be either an over collection or under collection) is then equal a pro-rata share of the total marginal

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\(^3\) A charge is calculated here because this difference (opportunity cost) has already been included in the Regulation-Up MCP.

\(^4\) A charge is calculated here because this difference has already been included in the Regulation-Down MCP.
losses over collection or under collection as calculated from the proxy loss charge contribution calculated in (a) above.

(14) Settlement (charges or credits) associated with services provided under Joint Operating Agreements are described under Section 4.5.9.21. These Charges or credits are collected or distributed as part of revenue neutrality uplift as described under Section 4.5.12;

(15) Settlement (charges or credits) associated with Contingency Reserve deployment involving Reserve Sharing Group members is accounted for as described under Section 4.5.9.22. These charges or credits are collected or distributed on a load ratio share as described under Section 4.5.9.23.

The following subsections describe the RTBM settlement charge types in more detail. For each charge type, the initial calculation is performed either at the Dispatch Interval level or hourly level for each Asset Owner at each Settlement Location. In addition to the Dispatch Interval and hourly values, hourly and daily values will be accessible on the Settlement Statement for all charge types.

4.5.9.8 RUC Make-Whole-Payment Amount

(1) The RUC Make-Whole-Payment Amount is a credit or charge5 to a Resource Asset Owner and is calculated for each Resource with a RUC Commitment Period that was committed by SPP with an RTBM Resource Offer Commitment Status of “Market” or “Reliability” as defined under Section 4.2.2.2.1 or that was committed by a local transmission operator that SPP determines were selected in a non-discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of Attachment AE to the Tariff are eligible to receive a RUC make whole payment. Resources issued commitment instructions by a local transmission operator in order to resolve a reliability issue may be eligible for make-whole-payments as defined in this Section if the selection of the Resource by the local transmission operator was performed in a non-discriminatory manner as determined by SPP; however, a manual process is employed for the calculations and the make-whole-payments will appear in the Miscellaneous Amount charge type defined in Section 4.5.11. The RUC Make-Whole-Payment Amount is also calculated for combined cycle Resources with a RUC Commitment Period during which the Resource is moved into a configuration that incurs additional costs over the Resource configuration used in the DA Market Commitment Period for the corresponding time period. A payment is made to the Resource Asset Owner when the sum of the Resource’s eligible RTBM Start-Up Offer costs, No-Load Offer costs, Energy Offer Curve, Transition State Offer costs and Operating Reserve Offer costs associated with actual MWh amounts for Energy and cleared RTBM Operating Reserve is greater than the Energy and Operating Reserve RTBM revenues received for that Resource over the Resource’s RUC Make-Whole-Payment Eligibility

5 Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
A Resource’s RUC Make-Whole-Payment Eligibility Period is equal to the Resource’s RUC Commitment Period except as described below:

(a) As shown in Exhibit 4-20, for Resources with a RUC Commitment Period that begins in one Operating Day and ends in the next Operating Day, two RUC Make-Whole-Payment Eligibility Periods are created. The first period begins in the first Operating Day in the Dispatch Interval associated with the Resource’s RUC Commit Time and ends at the last Dispatch Interval of the first Operating Day. The second period begins in the first Dispatch Interval of the next Operating Day and ends in the Dispatch Interval associated with the Resource’s RUC De-Commit Time.

(b) If the Resource is a combined cycle Resource committed in the DA Market and then, during an RTBM hour within the DA Market Commitment Period, the Resource is moved into a configuration that is different from the configuration used in the DA Market Commitment period and such configuration incurs a Transition State Offer cost and/or a No-Load Offer cost that is higher than the No-Load Offer cost associated with the configuration used in the DA Market, that RTBM hour will be considered the start of a RUC Make-Whole-Payment Eligibility Period. The end of this RUC Make-Whole-Payment Eligibility Period will be defined by the RTBM hour when the configuration in that RTBM hour is the same configuration as the configuration used in the corresponding DA Market Commitment Period hour, the Resource’s De-Commit Time or the end of the Operating Day, whichever is less.
The following cost recovery eligible rules apply to each RUC Make-Whole-Payment Eligibility Period. Offer costs are calculated using the RTBM Offer prices in effect at the time the commitment decision was made.

(a) If SPP cancels a start-up order prior to the start of the associated RUC Make-Whole-Payment Eligibility Period and the Resource is not a Synchronized Resource, the Asset Owner will receive reimbursement for a time-based pro-rata share of the Resource’s RTBM Start-Up Offer. Asset Owners may request additional compensation through submittal of actual cost documentation to the SPP. SPP will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

(b) In order to receive Start-Up Offer recovery within a RUC Make-Whole-Payment Eligibility Period, the Resource must be a Synchronized Resource for at least one Dispatch Interval in the RUC Make-Whole Payment Eligibility Period.

(c) In order to receive recovery of No-Load Offer costs in any Dispatch Interval in the RUC Make-Whole Payment Eligibility Period, the Resource must be a Synchronized Resource in that Dispatch Interval.

(d) There may be more than one RUC Make-Whole Payment Eligibility Period for a Resource in a single Operating Day for which a credit or charge is calculated. A single RUC Make-Whole Payment Eligibility Period is contained within a single Operating Day.

(e) A Resource’s RTBM Start-Up Offer costs are not eligible for recovery in the following RUC Make-Whole Payment Eligibility Periods:

   (i) Any RUC Make-Whole Payment Eligibility Period that is adjacent to the end of a DA Market Make-Whole Payment Eligibility Period;

   (ii) Any RUC Make-Whole Payment Eligibility Period for which a Resource is a Synchronized Resource prior to this commitment period at a time one hour prior to that Resource’s RUC Commit Time less the Resource’s Sync-To-Min Time; and

   (iii) Any RUC Make-Whole Payment Eligibility Period resulting from a RUC Commitment Period that contains an hour for which the Resource Commitment Status is Self-Commit.

(f) For each RUC Make-Whole Payment Eligibility Period within an Operating Day, a Resource’s RTBM Start-Up Offer is divided by the lesser of (1) the Resource’s Minimum Run Time multiplied by 12 rounded down to the nearest whole interval or (2) 24 Hours multiplied by 12, and that portion of the Start-Up Offer is included as a cost in each interval of the RUC Make-Whole Payment Eligibility Period until the sum of these interval costs are equal to the RTBM Start-Up Offer or until the end of the RUC Make-Whole Payment Eligibility Period, whichever occurs first.
(g) To the extent that the full amount of the RTBM Start-Up Offer is not accounted for in the last RUC Make-Whole Payment Eligibility Period in the Operating Day, any remaining RTBM Start-Up Offer costs are carried forward for recovery in the first RUC Make-Whole Payment Eligibility Period of the following Operating Day provided that the Resource has not been committed in the DA Market in any hour of the first RUC Make-Whole Payment Eligibility Period as described in (h) below. For example, consider a Resource that is committed starting at 10:00 PM in Operating Day 1 that has a Minimum Run Time of 10 hours and a Start-Up Offer of $12,000. The RUC Commitment Period is from 10:00 PM in Operating Day 1 through 8:00 AM of Operating Day 2. For RUC Make-Whole Payment calculation purposes, the RUC Commitment Period is split into two separate RUC Make-Whole Payment Eligibility Periods as described in (2).a above. The first RUC Make-Whole Payment Eligibility Period will include $100/interval of Start-Up Offer costs ($12,000 / 120 intervals) in hour 23 and 24 intervals. The second RUC Make-Whole Payment Eligibility Period will include $100/interval of Start-Up Offer costs in hours 1 through 8 intervals.

(h) If the Resource has been committed in the DA Market in a period adjacent to and following a RUC Make-Whole Payment Eligibility Period to the extent that the full amount of the RTBM Start-Up Offer is not accounted for in the RUC Make-Whole Payment Eligibility Period, any remaining RTBM Start-Up Offer costs are carried forward for recovery in the Day-Ahead Make-Whole Payment Eligibility Period.

(i) If the Resource is a combined cycle Resource, additional costs associated with situations in which the Resource has cleared Operating Reserve in the Day-Ahead Market and must buy back that position in Real-Time at a Real-Time MCP that is greater than the Day-Ahead MCP, the Market Participant may be eligible for a make-whole payment. To be eligible, these costs must be incurred during a time periods in which the Resource is transitioning between configurations, at the direction of SPP, and such cost is not due to any independent action of the Market Participant. In such cases, the additional costs are equal to the difference between the average Real-Time MCP and the Day-Ahead MCP multiplied by the Day-Ahead Market cleared Operating Reserve MW amounts. Recovery of these costs associated with Contingency Reserve is limited to the time period defined as the Transition State Time submitted in the Resource Offer. Recovery of these costs associated with Regulation-Up and/or Regulation-Down is limited to all Dispatch Intervals within the transition hour.

(3)(4) The amount to each Asset Owner (AO) for each eligible Resource Settlement Location for a given RUC Make-Whole Payment Eligibility Period is calculated as follows:

\[
#\text{RtMwpCpAmt}_{a,s,c} = \text{CncldStartAmt}_{a,s,c} + \text{Max}(0, \{ \text{IF} \ (\text{CncldStartRatio}_{a,s,c} = 0, \THEN \ 1, \ELSE \ 0) \})
\]
\[ \sum_{i} \{ \text{RtStartUpElig5minFlg}_{a,s,i,c} \times \text{RtStartUp5minAmt}_{a,s,i,c} \\
+ \text{RtRucComStat5minFlg}_{a,s,i,c} \times [ \text{RtMwpCost5minAmt}_{a,s,i,c} \\
+ \text{RtTransition5minAmt}_{a,s,i,c} + \text{RtWpRev5minAmt}_{a,s,i,c} \\
+ \text{RtOom5minAmt}_{a,s,i} + \text{RtRegAdj5minAmt}_{a,s,i} \\
- \text{RtURDAdj5minAmt}_{a,s,i,c} - \text{RtStatusAdj5minAmt}_{a,s,i,c} \\
- \text{RtLimitAdj5minAmt}_{a,s,i,c} \} \} \\
+ \sum_{h} ( \text{RtCcRegUpAdjHrlyAmt}_{a,s,h,c} + \text{RtCcRegDnAdjHrlyAmt}_{a,s,h,c} \\
+ \text{RtCcSpinAdjHrlyAmt}_{a,s,h,c} + \text{RtCcSuppAdjHrlyAmt}_{a,s,h,c} ) \} \} ) ) ) \times (-1) \]

Where,

(a) \#\text{RtMwpCost5minAmt}_{a,s,i,c} = \text{RtRucComStat5minFlg}_{a,s,i,c} * \\
\left( \text{RtIncrEn5minAmt}_{a,s,i} \\
+ \text{Max} ( 0, [ \text{RtNoLoad5minAmt}_{a,s,i,c} \\
- \text{IF} ( \text{DaClrdHrlyQty}_{a,s,h} < 0, \text{THEN} \text{DaNoLoadHrlyAmt}_{a,s,h,c}, \text{ELSE} 0 ) ] ) \\
+ \text{RtMinEn5minAmt}_{a,s,i,c} \\
+ \text{RtRegUpAvail5minAmt}_{a,s,i,c} + \text{RtRegDnAvail5minAmt}_{a,s,i,c} \\
+ \text{RtSpinAvail5minAmt}_{a,s,i,c} + \text{RtSuppAvail5minAmt}_{a,s,i,c} ) / 12 \]

(a.1) \text{IF} \text{ABS} ( \text{DaClrdHrlyQty}_{a,s,h} ) \geq \text{ABS} ( \text{RtBillMtr5minQty}_{a,s,i} ) \\
\text{THEN} \\
\text{RtIncrEn5minAmt}_{a,s,i} = 0 \\
\text{ELSE}
#RtIncrEn5minAmt_{a,s,i} = \int_x^y \text{RTBM As Dispatched Energy Offer Curve}

Where:

X = \text{Max} (\text{ABS} (\text{DaClrdHrlyQty}_{a,s,h}), \text{RtEffMin5minQty}_{a,s,i})

AND

IF ControlStatus5minFlg_{a,s,i} = "Regulating"

THEN

RtEffMin5minQty_{a,s,i} = \text{Min} (\text{RtComMinRegCapOL5minQty}_{a,s,i}, \text{RtDispMinRegCapOL5minQty}_{a,s,i}, \text{Max} (0, (-1) \times \text{RtBillMtr5minQty}_{a,s,i}))

ELSE

RtEffMin5minQty_{a,s,i} = \text{Min} (\text{RtComMinEconCapOL5minQty}_{a,s,i}, \text{RtDispMinEconCapOL5minQty}_{a,s,i}, \text{Max} (0, (-1) \times \text{RtBillMtr5minQty}_{a,s,i}))

AND

Y = \text{Max} ((-1) \times \text{RtBillMtr5minQty}_{a,s,i}, 0)

(a.2) IF ABS (\text{DaClrdHrlyQty}_{a,s,h}) \iff RtEffMin5minQty_{a,s,i} < 0

THEN
\[ \text{#RtMinEn5minAmt}_{a,s,i} = \int_{x}^{y} \text{RTBM As Committed Energy Offer Curve} \]

**Where:**

\[ X = \text{DaClrdHrlyQty}_{a,s,h} \]

\[ Y = \text{RtEffMin5minQty}_{a,s,i} \]

**ELSE**

**THEN**

\[ \text{RtMinEn5minAmt}_{a,s,i,c} = 0 \]

**ELSE**

\[ \text{#RtMinEn5minAmt}_{a,s,i,c} = \int_{0}^{\text{RTBM As Committed Energy Offer Curve}} \]

(a.3) If \( \text{RtRegUp5minQty}_{a,s,i} > \text{RtFixedRegUp5minQty}_{a,c,i} \)

**THEN**

\[ \text{RtRegUpAvail5minAmt}_{a,s,i,c} = \]

\[ \text{Max} \left( 0, \left[ \text{RtRegUp5minQty}_{a,s,i} - \sum_{z} \text{DaRegUpHrlyQty}_{a,z,s,h} \right] \right) \]

* \( \text{RtRegUpOffer}_{a,s,i,c} \)

**ELSE** \( \text{RtRegUpAvail5minAmt}_{a,s,i,c} = 0 \)

**IF** \( \text{RtTranistionStateFlg}_{a,s,i,c} = 1 \) **THEN**
\( \text{RtRegUpAvail5minAmt}_{a, s, i, c} = \sum_{i} \text{DaRegUpHrlyQty}_{a, z, s, h} \)

* Max ( 0, \( \text{RtRegUpMcp5minPre}_{a, i} - \text{DaRegUpMcpHrlyPre}_{a, h} \) )

Else

\( \text{RtRegUpAvail5minAmt}_{a, s, i, c} = \text{RtRegUpAvail5minAmt}_{a, s, i} = 0 \)

(a.4) If \( \text{RtRegDn5minQty}_{a, s, i} > \text{RtFixedRegDn5minQty}_{a, s, c, i} \)

Then

\( \text{RtRegDnAvail5minAmt}_{a, s, i, c} = \max (0, \text{RtRegDn5minQty}_{a, z, s, i} - \sum_{i} \text{DaRegDnHrlyQty}_{a, z, s, h}) \)

* \( \text{RtRegDnOffer}_{a, s, i, c} \)

Else

\( \text{RtRegDnAvail5minAmt}_{a, s, i, c} = 0 \)

\( \text{RtRegDnAvail5minAmt}_{a, s, i} = 0 \)

(a.5) If \( \text{RtSpin5minQty}_{a, s, i} > \text{RtFixedSpin5minQty}_{a, s, c, i} \)

Then

\( \text{RtSpinAvail5minAmt}_{a, s, i, c} = \max (0, \text{RtSpin5minQty}_{a, z, s, i} - \sum_{i} \text{DaSpinHrlyQty}_{a, z, s, h}) \)
* \( \text{RtSpinOffer} \ a, s, i, c \)

**ELSE**

\[ \text{RtSpinAvail5minAmt} \ a, s, i, c = 0 \]

**a.6** If \( \text{RtSupp5minQty} \ a, s, i > \text{RtFixedSupp5minQty} \ a, s, i \)

**THEN**

\[ \text{RtSuppAvail5minAmt} \ a, s, i, c = \]

\[ \text{Max} (0, \left[ \text{RtSupp5minQty} \ a, z, s, i - \sum z \text{DaSuppHrlyQty} \ a, z, s, h \right]) \]

* \( \text{RtSuppOffer} \ a, s, i, c \)

**ELSE**

\[ \text{RtSuppAvail5minAmt} \ a, s, i, c = 0 \]

\[ \text{RtSuppAvail5minAmt} \ a, s, i = 0 \]

(b) \( \#\text{RtMwpRev5minAmt} \ a, s, i, c = \)

\[ \text{RtRucComStat5minFlg} \ a, s, i, c \ * \left( \left( \text{RtLmp5minPrc} \ s, i \right) \ * \text{Min}(0, \left[ \text{RtBillMtr5minQty} \ a, s, i - \text{DaClrdHrlyQty} \ a, s, h \right]) / 12 \right) \] + \text{RtRegUpRev5minAmt} \ a, s, i, c + \text{RtRegDnRev5minAmt} \ a, s, i, c + \text{RtSpinRev5minAmt} \ a, s, i, c + \text{RtSuppRev5minAmt} \ a, s, i, c \]

(b.1) \( \text{RtRegUpRev5minAmt} \ a, s, i, c = \) \((-1) \ * \text{RtRucComStat5minFlg} \ a, s, i, c \)
(b.2) \[ \text{RtRegDnRev5minAmt}_{a,s,i,c} = \]

\[ (-1) \times \text{RtRucComStat5minFlg}_{a,s,i,c} \]

*( Max ( 0, [ RtRegDn5minQty}_{a,z,s,i} - \sum_z \text{DaRegDnHrlyQty}_{a,z,s,h} ] )

* \text{RtRegDnMcp5minPrc}_{z,i} ) / 12

(b.3) \[ \text{RtSpinRev5minAmt}_{a,s,i,c} = \]

\[ (-1) \times \text{RtRucComStat5minFlg}_{a,s,i,c} \]

*( Max ( 0, [ RtSpin5minQty}_{a,z,s,i} - \sum_z \text{DaSpinHrlyQty}_{a,z,s,h} ] )

* \text{RtSpinMcp5minPrc}_{z,i} ) / 12

(b.4) \[ \text{RtSuppRev5minAmt}_{a,s,i,c} = \]

\[ (-1) \times \text{RtRucComStat5minFlg}_{a,s,i,c} \]

*( Max ( 0, [ RtSupp5minQty}_{a,z,s,i} - \sum_z \text{DaSuppHrlyQty}_{a,z,s,h} ] )

* \text{RtSuppMcp5minPrc}_{z,i} ) / 12

(c) \[ \#\text{CncldStartAmt}_{a,s,c} = \]

\[ \sum_i ( \text{RtStartUp5minAmt}_{a,s,i,c} \times \text{RtStartUpElig5minFlg}_{a,s,i,c} ) \]
\* CncldStartRatio_{a,s,c}

\[
\text{CncldStartRatio}_{a,s,c} = \left( \frac{\text{ElapsedTime}_{a,s,c}}{\text{StartUpTime}_{a,s,c}} \right)
\]

(d) In any Dispatch Interval in which the Resource has operated outside of its Operating Tolerance and that Resource has not been exempted from URD per Section 4.4.4.1, any incremental Energy costs associated with actual Energy output above the Resource’s Desired Dispatch is not eligible for recovery. The URD adjustment is calculated as follows:

IF \( \text{ABS} (\text{URD}_{5\text{minQty}}_{a,s,i}) > \text{ResOpTol}_{5\text{minQty}}_{a,s,i} \) AND

( \text{XmptDev}_{5\text{minFlg}}_{a,s,i} = 0 )

THEN

\#RtURDAdj_{5\text{minAmt}}_{a,s,i,c} = \text{RtRucComStat}_{5\text{minFlg}}_{a,s,i,c} * \text{Max} (0, (\text{RtIncrEn}_{5\text{minAmt}}_{a,s,i} - \text{RtDesiredEn}_{5\text{minAmt}}_{a,s,i}))/12

ELSE

RtURDAdj_{5\text{minAmt}}_{a,s,i,c} = 0

(d.1) \text{URD}_{5\text{minQty}}_{a,s,i} =

\left( \text{RtBillMtr}_{5\text{minQty}}_{a,s,i} \right)^* (-1)) - \text{RtAvgSetPoint}_{5\text{minQty}}_{a,s,i}

(d.2) \text{ResOpTol}_{5\text{minQty}}_{a,s,i} =

\text{Min} (\text{URDMaxTol}_{5\text{minQty}}_{i}, \text{Max}(\text{URDMinTol}_{5\text{minQty}}_{i}, \text{URDTol}_{5\text{minPct}}_{i} \ast \text{RtDispMaxEmerCapOL}_{5\text{minQty}}_{a,s,i} ) )

(d.3) IF \text{RtDesiredEn}_{5\text{minQty}}_{a,s,i} < \text{ABS} (\text{DaClrdHrlyQty}_{a,s,h} )

THEN

\#RtDesiredEn_{5\text{minAmt}}_{a,s,i} = \text{RtIncrEn}_{5\text{minAmt}}_{a,s,i}

ELSE

\#RtDesiredEn_{5\text{minAmt}}_{a,s,i} = \int_{x}^{y} \text{RTBM As Dispatched Energy Offer Curve}
Where:

\[ X = \text{Max} \left( \text{ABS} \left( \text{DaClrdHrlyQty}_{a,s,h} \right), \text{RtEffMin5minQty}_{a,s,i} \right) \]

\[ Y = \text{RtDesiredEn5minQty}_{a,s,i} \]

(e) In any Dispatch Interval in which a Resource is in “Manual” status, any incremental Energy costs associated with actual Energy output above the Resource’s Desired Dispatch is not eligible for recovery. The status change adjustment is calculated as follows:

\[
\text{IF} \quad \text{ControlStatus5minFlg}_{a,s,i} = \text{“Manual”} \\
\text{AND} \quad \text{ABS} \left( \text{URD5minQty}_{a,s,i} \right) \leq \text{ResOpTol5minQty}_{a,s,i} \\
\text{THEN} \\
\#\text{RtStatusAdj5minAmt}_{a,s,i,c} = \text{RtRucComStat5minFlg}_{a,s,i,c} \times \text{Max} \left( 0, \left( \text{RtIncrEn5minAmt}_{a,s,i} - \text{RtDesiredEn5minAmt}_{a,s,i} \right) \right) / 12 \\
\text{ELSE} \\
\text{RtStatusAdj5minAmt}_{a,s,i,c} = 0
\]

(f) In any Dispatch Interval in which a Resource has increased its Minimum Economic Capacity Operating Limit (or its Minimum Regulation Capacity Operating Limit if the Resource has cleared for Regulation-Up or Regulation-Down) above the Resource’s minimum limits used by SPP in the commitment decision or the minimum limits used to move from one configuration to another in the case of a \( \odot \circ \)combined \( \odot \circ \)cycle Resource, the Resource is not in “Manual” status and the increase in minimum limit is greater than the Resource’s Operating Tolerance, any incremental Energy costs associated with actual Energy output above the Resource’s Desired Dispatch is not eligible for recovery. The limit change adjustment is calculated as follows:

\[
\text{IF} \quad \text{ControlStatus5minFlg}_{a,s,i} \neq \text{“Regulating”} \quad \text{AND} \\
\text{ControlStatus5minFlg}_{a,s,i} \neq \text{“Manual”} \quad \text{AND} \\
\left( \text{RtDispMinEconCapOL5minQty}_{a,s,i} - \text{RtComMinEconCapOL5minQty}_{a,s,i} \right) > \text{ResOpTol5minQty}_{a,s,i} \\
\text{AND}
\]
ABS (URD5minQty \(a, s, i\)) \leq \text{ResOpTol5minQty} \(a, s, i\)

THEN

\#RtLimitAdj5minAmt \(a, s, i, c\) = \text{RtRucComStat5minFlg} \(a, s, i, c\)

* \text{Max} \left( 0, \left( \text{RtincrEn5minAmt} \(a, s, i\) - \text{RtDesiredEn5minAmt} \(a, s, i\) \right) \right) / 12

ELSE IF

\text{ControlStatus5minFlg} \(a, s, i\) = \text{“Regulating” AND}

( \text{RtDispMinRegCapOL5minQty} \(a, s, i\)

- \text{RtComMinRegCapOL5minQty} \(a, s, i\) ) > \text{ResOpTol5minQty} \(a, s, i\) AND

ABS (URD5minQty \(a, s, i\)) \leq \text{ResOpTol5minQty} \(a, s, i\)

THEN

\#RtLimitAdj5minAmt \(a, s, i, c\) = \text{RtRucComStat5minFlg} \(a, s, i, c\)

* \text{Max} \left( 0, \left( \text{RtincrEn5minAmt} \(a, s, i\) - \text{RtDesiredEn5minAmt} \(a, s, i\) \right) \right) / 12

ELSE

\text{RtLimitAdj5minAmt} \(a, s, i, c\) = 0

(g) If \(\sum \text{RtTranistionStateFlg} \(a, s, i, c\) \geq 1\) THEN

\text{RtCcRegUpAdjHrlyAmt} \(a, s, h, c\) =

* \text{Max} \left( 0, \sum \text{RtCcRegUpAdj5minAmt} \(a, s, i, c\) \text{RtRucComStat5minFlg} \(a, s, i, c\) \right)

ELSE

\text{RtCcRegUpAdjHrlyAmt} \(a, s, h, c\) = 0

(g.1) \text{RtCcRegUpAdj5minAmount} \(a, s, i, c\) =
(DaRegUpHrlyAmt_{a,s,h} / 12 + RtRegUp5minAmt_{a,s,i,j})

ELSE

RtCcRegUpAdj5minAmt_{a,s,i,c} = 0

(h) If \(\sum_{i} RtTranistionStateFlg_{a,s,i,c} \geq 1\) THEN

RtCcRegDnAdjHrlyAmt_{a,s,h,c} =

\[
* \text{Max} \left( 0, \sum_{i} \left( \text{RtCcRegDnAdj5minAmt}_{a,s,i,c} * \text{RtRucComStat5minFlg}_{a,s,i,c} \right) \right)
\]

ELSE

RtCcRegDnAdjHrlyAmt_{a,s,h,c} = 0

(h.1) RtCcRegDnAdj5minAmt_{a,s,i,c} =

(DaRegDnHrlyAmt_{a,s,h} / 12 + RtRegUp5minAmt_{a,s,i,j})

ELSE

RtCcRegDnAdj5minAmt_{a,s,i,c} = 0

(i) If RtTranistionStateFlg_{a,s,i,c} = 1 THEN

RtCcSpinAdj5minAmt_{a,s,i,c} =

RtRucComStat5minFlg_{a,s,i,c} * (DaSpinHrlyAmt_{a,s,h} / 12 + RtSpin5minAmt_{a,s,i,j})

ELSE

RtCcSpin5minAmt_{a,s,i,c} = 0
(i.1) \[ \text{RtCcSpinAdjHrlyAmt}_{a, s, h, c} = \]
\[ \text{Max} \left( 0, \sum_i \text{RtCcSpinAdj5minAmt}_{a, s, i, c} \right) \]

(j) IF \(\text{RtTransitionStateFlg}_{a, s, i} = 1\) THEN
\[ \text{RtCcSuppAdj5minAmt}_{a, s, i, c} = \]
\[ \text{RtRucComStat5minFlg}_{a, s, i, c} \times (\text{DaSuppHrlyAmt}_{a, s, h}/12 + \text{RtSupp5minAmt}_{a, s, i}) \]
ELSE
\[ \text{RtCcSupp5minAmt}_{a, s, i, c} = 0 \]

(j.1) \[ \text{RtCcSuppAdjHrlyAmt}_{a, s, h, c} = \]
\[ \text{Max} \left( 0, \sum_i \text{RtCcSuppAdj5minAmt}_{a, s, i, c} \right) \]

(4)(5) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:
\[ \text{RtMwpDlyAmt}_{a, s, d} = \sum_c \text{RtMwpCpAmt}_{a, s, c} \]

(5)(6) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:
\[ \text{RtMwpAoAmt}_{a, m, d} = \sum_s \text{RtMwpDlyAmt}_{a, s, d} \]

(6)(7) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:
\[ \text{RtMwpMpAmt}_{m, d} = \sum_a \text{RtMwpAoAmt}_{a, m, d} \]

(8) For FERC Electric Quarterly Reporting (“EQR”) purposes, SPP calculates RUC Make-Whole Payment $ per RUC Make-Whole-Payment Eligibility Period for each Asset Owner as follows:
(a) \[ \text{EqrRtMwp5minPrc}_{a,s,c} = (-1) \times \text{RtMwpCpAmt}_{a,s,c} \]

(b) IF \[ \text{EqrRtMwp5minPrc}_{a,s,c} > 0 \]
THEN
\[ \text{EqrRtMwp5minQty}_{a,s,c} = 1 \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtMwpCpAmt (_{a,s,c})</td>
<td>$</td>
<td>Elongibility Period</td>
<td><strong>RUC Make-Whole-Payment Amount per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period</strong> - The amount to AO (a) for RUC Make-Whole-Payment Eligibility Period (c) at Resource Settlement Location (s).</td>
</tr>
<tr>
<td>DaClrdHrlyQty (_{a,s,h})</td>
<td>MWh</td>
<td>Hour</td>
<td><strong>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour</strong> - The value described under Section 4.5.8.1 for AO (a)’s combined cycle resource at Settlement Location (s) for the Hour.</td>
</tr>
<tr>
<td>RtTransition5minAmt (_{a,s,i,c})</td>
<td>$</td>
<td>Elongibility Period</td>
<td><strong>Real-Time Transition Cost Amount per AO per Settlement Location in RUC Make-Whole-Payment Eligibility Period</strong> - The RTBM Transition State Offer associated with AO (a)’s eligible combined cycle Resource at Settlement Location (s) in Dispatch Interval (i) in RUC Make-Whole-Payment Eligibility Period (c).</td>
</tr>
<tr>
<td>RtTransitionStateFlg (_{a,s,i,c})</td>
<td>Flag</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Transition State Flag per AO per Settlement Location in RUC Make-Whole-Payment Eligibility Period</strong> – This flag is set to 1 in Dispatch Interval (i) for Asset Owner (a) when a combined cycle Resource at Settlement Location (s) is transitioning from one configuration to another in RUC Make-Whole-Payment Eligibility Period (c).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------</td>
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</tr>
<tr>
<td>RtStartUp5minAmt&lt;sub&gt;a,s,i,c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Real-Time Start-Up Cost Amount per AO per Settlement Location per Dispatch Interval per RUC Make-Whole-Payment Eligibility Period - The RTBM Start-Up Offer associated with AO a’s eligible Resource at Settlement Location s for RUC Make-Whole-Payment Eligibility Period c in Dispatch Interval i. This value is calculated by dividing RtStartUpAmt&lt;sub&gt;a,s,c&lt;/sub&gt; by the lesser of the Resource’s (RtMinRunTime&lt;sub&gt;a,i,s,c&lt;/sub&gt; *12) or (24 * 12). These interval values are carried forward into the following Operating Day, if needed, to ensure recovery of any remaining RtStartUpAmt&lt;sub&gt;a,s,c&lt;/sub&gt;.</td>
</tr>
<tr>
<td>RtStartUpAmt&lt;sub&gt;a,s,c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Real-Time Start-Up Cost Amount per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period - The RTBM Start-Up Offer used in the commitment decision, associated with AO a’s eligible Resource at Settlement Location s for RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtStartUpElig5minFlg&lt;sub&gt;a,s,i,c&lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>RUC Start-Up Recovery Eligibility Flag per AO per Resource Settlement Location per Dispatch Interval per RUC Make-Whole-Payment Eligibility Period – This flag is set equal to 1 in each Dispatch Interval of a RUC Make-Whole-Payment Eligibility Period where the Resource is eligible to recover start-up costs, or 0 where the Resource is not eligible to recover start-up costs.</td>
</tr>
<tr>
<td>RtRucComStat5minFlg&lt;sub&gt;a,s,i,c&lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>RUC Commitment Status Flag per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – This flag is set equal to 1 for each Dispatch Interval of a RUC Make-Whole-Payment Eligibility Period in which a Resource’s Commitment Status was “Market” or “Reliability”, or 0 if its Commitment Status was “Self”.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>CncldStartRatio&lt;sub&gt;a, s, c&lt;/sub&gt;</td>
<td>None</td>
<td></td>
<td><em>Canceled Start Ratio per Resource Settlement Location in RUC Make-Whole-Payment Eligibility Period</em> – The ratio of <code>ElapsedTime&lt;sub&gt;a, s, c&lt;/sub&gt;</code> to <code>StartUpTime&lt;sub&gt;a, s, c&lt;/sub&gt;</code> as calculated for each Dispatch Interval in RUC Make-Whole-Payment Eligibility Period &lt;sub&gt;c&lt;/sub&gt;.</td>
</tr>
<tr>
<td>RtMinRunTime&lt;sub&gt;a, i, s, c&lt;/sub&gt;</td>
<td>Time</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Minimum Run Time per AO per Settlement Location per Dispatch Interval per RUC Make-Whole-Payment Eligibility Period</em> – The Minimum Run Time used in the commitment decision, associated with AO a’s eligible Resource at Settlement Location s for RUC Make-Whole-Payment Eligibility Period &lt;sub&gt;c&lt;/sub&gt; as submitted as part of the RTBM Market Offer.</td>
</tr>
<tr>
<td>RtSynchToMinTime&lt;sub&gt;a, i, s, c&lt;/sub&gt;</td>
<td>Time</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Synch To Minimum Time per AO per Settlement Location per Dispatch Interval per RUC Make-Whole-Payment Eligibility Period</em> – The Synch To Minimum Time used in determining Start-Up Recovery Eligibility, associated with AO a’s eligible Resource at Settlement Location s for RUC Make-Whole-Payment Eligibility Period &lt;sub&gt;c&lt;/sub&gt; as submitted as part of the RTBM Market Offer.</td>
</tr>
<tr>
<td>RtNoLoad5minAmt&lt;sub&gt;a, i, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time No-Load Cost Amount per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</em> - The No-Load Offer used in the commitment decision, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period &lt;sub&gt;c&lt;/sub&gt;.</td>
</tr>
<tr>
<td>RtMwpCost5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>RUC Make-Whole-Payment Cost per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</em> – The total Energy and Operating Reserve cost at actual Resource output, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period &lt;sub&gt;c&lt;/sub&gt;.</td>
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</tr>
<tr>
<td>RtMwpRev5minAmt (_{a, s, i, c})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>RUC Make-Whole-Payment Revenue per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</em> – The total Energy and Operating Reserve revenue at actual Resource output, in dollars, associated with AO (_a)'s eligible Resource at Settlement Location (_s) for Dispatch Interval (_i) in RUC Make-Whole-Payment Eligibility Period (_c).*</td>
</tr>
<tr>
<td>CncldStartAmt (_{a, s, c})</td>
<td>$</td>
<td>Eligibility Period</td>
<td><em>Real-Time Cancelled Start Amount per AO per Settlement Location per for the RUC Make-Whole-Payment Eligibility Period</em> – The Start-Up Offer cost reimbursement for an SPP cancelled start-up, in dollars, associated with AO (_a)'s eligible Resource at Settlement Location (_s) for RUC Make-Whole-Payment Eligibility Period (_c).*</td>
</tr>
<tr>
<td>ElapsedTime (_{a, s, c})</td>
<td>Time</td>
<td>Eligibility Period</td>
<td><em>Elapsed Time per AO per Settlement Location per for the RUC Make-Whole-Payment Eligibility Period</em> – The elapsed time, in minutes, between the start of a Resource’s StartUpTime (_{a, s, c}) and the time SPP cancelled the start-up, in dollars, associated with AO (_a)'s eligible Resource at Settlement Location (_s) for RUC Make-Whole-Payment Eligibility Period (_c).*</td>
</tr>
<tr>
<td>StartUpTime (_{a, s, c})</td>
<td>Time</td>
<td>Eligibility Period</td>
<td><em>Start-up Time per AO per Settlement Location for the RUC Make-Whole-Payment Eligibility Period</em> – The Start-Up Time, in minutes, used in the commitment decision associated with AO (_a)'s eligible Resource at Settlement Location (_s) for RUC Make-Whole-Payment Eligibility Period (_c) as specified in the RTBM Offer submitted prior to the RUC Make-Whole-Payment Eligibility Period.*</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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<tr>
<td>RtURDAj5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>URD Adjustment per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period – The reduction in RUC Make-Whole Payment Amount associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c when the Resource’s URD5minQty&lt;sub&gt;a, s, i&lt;/sub&gt; is outside of the Resource’s ResOpTol5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;.</td>
</tr>
<tr>
<td>URD5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation per AO per Settlement Location per Dispatch Interval – The Uninstructed Resource Deviation associated with AO a’s Resource at Settlement Location s in Dispatch Interval i.</td>
</tr>
<tr>
<td>ResOpTol5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Resource Operating Tolerance per AO per Settlement Location per Dispatch Interval – The Resource Operating Tolerance associated with AO a’s Resource at Settlement Location s in Dispatch Interval i.</td>
</tr>
<tr>
<td>URDMaxTol5minQty&lt;sub&gt;i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation Maximum Tolerance per Dispatch Interval – The maximum value of ResOpTol5minQty&lt;sub&gt;a, s, i&lt;/sub&gt; that is currently set at 20 MW.</td>
</tr>
<tr>
<td>URDMinTol5minQty&lt;sub&gt;i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation Minimum Tolerance per Dispatch Interval – The minimum value of ResOpTol5minQty&lt;sub&gt;a, s, i&lt;/sub&gt; that is currently set at 5 MW.</td>
</tr>
<tr>
<td>URDTol5minPct&lt;sub&gt;i&lt;/sub&gt;</td>
<td>Percent</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation Tolerance Percentage per Dispatch Interval – The percentage used to calculate the value of ResOpTol5minQty&lt;sub&gt;a, s, i&lt;/sub&gt; that is currently set at 5%.</td>
</tr>
<tr>
<td>RtAvgSetPoint5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Average Setpoint Instruction MW per AO per Settlement Location per Dispatch Interval – The average Setpoint Instruction over Dispatch Interval i for AO a’s Resource at Settlement Location s.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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</tr>
<tr>
<td>XmptDev5minFlg&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>URD Exemption Flag per AO per Resource Settlement Location per Dispatch Interval – A flag associated with AO a’s eligible Resource at Settlement Location s indicating that a Resource that has operated outside of its Operating Tolerance is or is not exempt from any associated penalty charges in Dispatch Interval i. If the flag is equal to zero, the Resource is not exempt. Otherwise, the flag will be set to a positive integer number which will indicate the reason of the exemption as specified under Section 4.4.4.1.</td>
</tr>
<tr>
<td>RtStatusAdj5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Resource Status Change Adjustment per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period – The reduction in RUC Make-Whole Payment Amount associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c when the Resource’s Control Status is set to “Manual”.</td>
</tr>
<tr>
<td>ControlStatus5minFlg&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Control Status per AO per Settlement Location per Dispatch Interval – A Resource status indicator associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i as set by SPP operators that indicates the current dispatchable status of the Resource.</td>
</tr>
<tr>
<td>RtDispMaxEmerCapOL5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Maximum Emergency Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Maximum Emergency Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtEffMin5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Effective Minimum Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Effective Minimum Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>Variable</td>
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<td>Definition</td>
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<tr>
<td>RtDispMinEconCapOL5minQty ( a, s, i )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Minimum Economic Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval</strong> – The Minimum Economic Capacity Operating Limit associated with AO ( a )'s eligible Resource at Settlement Location ( s ) for Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>RtDispMinRegCapOL5minQty ( a, s, i )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Minimum Regulation Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval</strong> – The Minimum Regulation Capacity Operating Limit associated with AO ( a )'s eligible Resource at Settlement Location ( s ) for Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>RtLimitAdj5minAmt ( a, s, i, c )</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Resource Limit Change Adjustment per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</strong> – The reduction in RUC Make-Whole Payment Amount associated with AO ( a )'s eligible Resource at Settlement Location ( s ) for Dispatch Interval ( i ) in RUC Make-Whole-Payment Eligibility Period ( c ) for a Real-Time increase in minimum limit.</td>
</tr>
<tr>
<td>RtComMinEconCapOL5minQty ( a, s, i )</td>
<td>MW</td>
<td>Eligibility Period</td>
<td><strong>Real-Time Minimum Economic Capacity Operating Limit Quantity per AO per Settlement Location</strong> – The Minimum Economic Capacity Operating Limit associated with AO ( a )'s eligible Resource at Settlement Location ( s ) for Dispatch Interval ( i ) as submitted in an RTBM Offer prior to the RUC Make-Whole-Payment Eligibility Period that was used in making the initial Resource commitment decision or was used in making the decision to move from one configuration to another in the case of a combined cycle Resource.</td>
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<tr>
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<tr>
<td>RtComMinRegCapOL5minQty (_{a, s, i})</td>
<td>MW</td>
<td>Eligibility Period</td>
<td>Real-Time Minimum Regulation Capacity Operating Limit Quantity per AO per Settlement Location—The Minimum Regulation Capacity Operating Limit associated with AO (_a)'s) eligible Resource at Settlement Location (_s) for Dispatch Interval (_i) as submitted in an RTBM Offer prior to the RUC Make-Whole-Payment Eligibility Period that was used in making the initial Resource commitment or was used in making the decision to move from one configuration to another in the case of a combined cycle Resource.</td>
</tr>
<tr>
<td>RtIncrEn5minAmt (_{a, s, i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Incremental Energy Cost Amount per AO per Settlement Location per Dispatch Interval - The average incremental energy offer cost, in dollars, associated with AO (_a)'s) eligible Resource at Settlement Location (_s) for Dispatch Interval (<em>i) from the Effective Minimum Capacity Operating Limit to (\text{RtBillMtr5minQty}</em>{a, s, i}).</td>
</tr>
<tr>
<td>RtMinEn5minAmt (_{a, s, i, c})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Energy Cost at Minimum Limit per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period - The average incremental energy offer cost at the Effective Minimum Capacity Operating Limit associated with AO (_a)'s) eligible Resource at Settlement Location (_s) for Dispatch Interval (_i) in RUC Make-Whole-Payment Eligibility Period (_c).</td>
</tr>
<tr>
<td>RtDesiredEn5minAmt (_{a, s, i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Energy Cost at Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval - The average incremental energy offer cost associated with AO (_a)'s) eligible Resource at Settlement Location (_s) for Dispatch Interval (<em>i), in dollars, from the Effective Minimum Capacity Operating Limit to (\text{RtDesiredEn5minQty}</em>{a, s, i}).</td>
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<tr>
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<tr>
<td>RtDesiredEn5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval</strong> – The Desired Dispatch MW for AO (_a)’s eligible Resource for Dispatch Interval (<em>i) at RtLmp5minPre (</em>{s,i}) as calculated from the Resource’s As Dispatched Energy Offer Curve using the As-Committed Minimum Capacity Limit (Economic or Regulating, as applicable) as an output floor and the As-Committed Maximum Capacity Limit (Economic or Regulating, as applicable) as an output ceiling.</td>
</tr>
<tr>
<td>RtOom5minAmt (_{a,s,i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Out-Of-Merit Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval</strong> - The value calculated under Section 4.5.9.9.</td>
</tr>
<tr>
<td>RtRegAdj5minAmt (_{a,s,i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Regulation Deployment Adjustment Amount per AO per Resource Settlement Location per Dispatch Interval</strong> - The value calculated under Section 4.5.9.19.</td>
</tr>
<tr>
<td>RtRegUpOffer (_{a,s,i,c})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Regulation-Up Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</strong> – The Regulation-Up Offer associated with AO (_a)’s Resource Settlement Location (_s) at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period (_c) in Dispatch Interval (_i).</td>
</tr>
<tr>
<td>RtRegDnOffer (_{a,s,i,c})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Regulation-Down Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</strong> – The Regulation-Down Offer associated with AO (_a)’s Resource Settlement Location (_s) at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period (_c) in Dispatch Interval (_i).</td>
</tr>
<tr>
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<tr>
<td><strong>RtSpinOffer</strong>&lt;sub&gt;a, s, i, c&lt;/sub&gt; * (Not Available on Settlement Statement)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Spinning Reserve Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</em> – The Spinning Reserve Offer associated with AO a’s Resource Settlement Location s at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period c in Dispatch Interval i.</td>
</tr>
<tr>
<td><strong>RtSuppOffer</strong>&lt;sub&gt;a, s, i, c&lt;/sub&gt; * (Not Available on Settlement Statement)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Supplemental Reserve Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</em> – The Supplemental Reserve Offer associated with AO a’s Resource Settlement Location s at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period c in Dispatch Interval i.</td>
</tr>
<tr>
<td><strong>RtFixedRegUp5minQty</strong>&lt;sub&gt;a, s, c, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Fixed Regulation-Up Quantity per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</em> – The Fixed Regulation-Up MW specified in the Regulation-Up Offer associated with AO a’s Resource Settlement Location s at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period c in Dispatch Interval i.</td>
</tr>
<tr>
<td><strong>RtFixedRegDn5minQty</strong>&lt;sub&gt;a, s, c, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Fixed Regulation-Down Quantity per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</em> – The Fixed Regulation-Down MW specified in the Regulation-Down Offer associated with AO a’s Resource Settlement Location s at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period c in Dispatch Interval i.</td>
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<tr>
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<tr>
<td>RtFixedSpin5minQty (_{a,s,c,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Fixed Spinning Reserve Quantity per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Fixed Spinning Reserve MW specified in the Spinning Reserve Offer associated with AO (a)’s Resource Settlement Location (s) at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period (c) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtFixedSupp5minQty (_{a,s,c,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Fixed Supplemental Reserve Quantity per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Fixed Supplemental Reserve MW specified in the Supplemental Reserve Offer associated with AO (a)’s Resource Settlement Location (s) at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period (c) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtRegUpAvail5minAmt (_{a,s,i,c})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Offer Cost Amount per AO per Resource Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period - The Regulation-Up Offer cost, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i) in RUC Make-Whole-Payment Eligibility Period (c).</td>
</tr>
<tr>
<td>RtRegDnAvail5minAmt (_{a,s,i,c})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Down Offer Cost Amount per AO per Resource Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period - The Regulation-Down Offer cost, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i) in DA Market Commitment Period (c).</td>
</tr>
<tr>
<td>RtSpinAvail5minAmt (_{a,s,i,c})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Spin Offer Cost Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period - The Spinning Reserve Offer cost, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i) in RUC Make-Whole-Payment Eligibility Period (c).</td>
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<tr>
<td>RtSuppAvail5minAmt (_{a,s,i,c})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Offer Cost Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period - The Supplemental Reserve Offer cost, in dollars, associated with AO a's eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtLmp5minPrc (_{s,i})</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time LMP - The value defined under Section 4.5.9.1 at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtBillMtr5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Actual Meter Quantity per AO per Location per Dispatch Interval - The value defined under Section 4.5.9.1 for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtRegUpMcp5minPrc (_{z,i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time MCP for Regulation-Up per Reserve Zone - The value defined under Section 4.5.9.4.</td>
</tr>
<tr>
<td>RtRegDnMcp5minPrc (_{z,i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time MCP for Regulation-Down per Reserve Zone - The value defined under Section 4.5.9.5.</td>
</tr>
<tr>
<td>RtSpinMcp5minPrc (_{z,i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time MCP for Spinning Reserve per Reserve Zone - The value defined under Section 4.5.9.6.</td>
</tr>
<tr>
<td>RtSuppMcp5minPrc (_{z,i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time MCP for Supplemental Reserve per Reserve Zone - The value defined under Section 4.5.9.7.</td>
</tr>
<tr>
<td>RtCcRegUpAdjHrlyAmt (_{a,s,h,c})</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Combined Cycle Regulation-Up Cost Adjustment per AO per Settlement Location per Hour – the additional cost incurred by AO a at Combined Cycle Settlement Location s associated with the buying back of Day-Ahead Market Regulation-Up positions during transitions between configurations for Hour h.</td>
</tr>
<tr>
<td>RtCcRegDnAdjHrlyAmt (_{a,s,h,c})</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Combined Cycle Regulation-Down Cost Adjustment per AO per Settlement Location per Hour – the additional cost incurred by AO a at Combined Cycle Settlement Location s associated with the buying back of Day-Ahead Market Regulation-Down positions during transitions between configurations for Hour h.</td>
</tr>
<tr>
<td>RtCcSpinAdjHrlyAmt (_{a,s,h,c})</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Combined Cycle Spinning Reserve Cost Adjustment per AO per Settlement Location per Hour –</td>
</tr>
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<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
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<tbody>
<tr>
<td>RtCcSuppAdjHrlyAmt&lt;sub&gt;a, s, h, c&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>the additional cost incurred by AO&lt;sub&gt;a&lt;/sub&gt; at Combined Cycle Settlement Location&lt;sub&gt;s&lt;/sub&gt; associated with the buying back of Day-Ahead Market Spinning Reserve position during transitions between configurations for Hour&lt;sub&gt;h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>RtCcRegUpAdj5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Combined Cycle Regulation-Up Cost Adjustment per AO per Settlement Location per Dispatch Interval – the additional cost incurred by AO&lt;sub&gt;a&lt;/sub&gt; at Combined Cycle Settlement Location&lt;sub&gt;s&lt;/sub&gt; associated with the buying back of Day-Ahead Market Regulation-Up position during transitions between configurations for Dispatch Interval&lt;sub&gt;i&lt;/sub&gt;.</td>
</tr>
<tr>
<td>RTCcRegDnAdj5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Combined Cycle Regulation-Down Cost Adjustment per AO per Settlement Location per Dispatch Interval – the additional cost incurred by AO&lt;sub&gt;a&lt;/sub&gt; at Combined Cycle Settlement Location&lt;sub&gt;s&lt;/sub&gt; associated with the buying back of Day-Ahead Market Regulation-Down position during transitions between configurations for Dispatch Interval&lt;sub&gt;i&lt;/sub&gt;.</td>
</tr>
<tr>
<td>RtCcSpinAdj5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Combined Cycle Spinning Reserve Cost Adjustment per AO per Settlement Location per Dispatch Interval – the additional cost incurred by AO&lt;sub&gt;a&lt;/sub&gt; at Combined Cycle Settlement Location&lt;sub&gt;s&lt;/sub&gt; associated with the buying back of Day-Ahead Market Spinning Reserve position during transitions between configurations for Dispatch Interval&lt;sub&gt;i&lt;/sub&gt;.</td>
</tr>
<tr>
<td>RTCcSuppAdj5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Combined Cycle Supplemental Reserve Cost Adjustment per AO per Settlement Location per Dispatch Interval – the additional cost incurred by AO&lt;sub&gt;a&lt;/sub&gt; at Combined Cycle Settlement Location&lt;sub&gt;s&lt;/sub&gt; associated with the buying back of Day-Ahead Market Supplemental Reserve position during transitions between configurations for Dispatch Interval&lt;sub&gt;i&lt;/sub&gt;.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtRegUpRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Real-Time incremental Regulation-Up revenue associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtRegDnRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Down Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Real-Time incremental Regulation-Down revenue associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtSpinRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Spinning Reserve Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Real-Time incremental Spinning Reserve associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtSuppRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Reserve Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Real-Time incremental Supplemental Reserve revenue associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtMwpDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Amount per AO per Settlement Location per Operating Day - The RUC Make-whole amount to AO a for Operating Day d at Resource Settlement Location s.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>$\text{RtMwpAoAmt}_{a,m,d}$</td>
<td>$$</td>
<td>Operating Day</td>
<td><em>RUC Make-Whole-Payment Amount per AO per Operating Day</em> - The RUC make-whole amount to AO $a$ associated with Market Participant $m$ for Operating Day $d$.</td>
</tr>
<tr>
<td>$\text{RtMwpMpAmt}_{m,d}$</td>
<td>$$</td>
<td>Operating Day</td>
<td><em>RUC Make-Whole-Payment Amount per MP per Operating Day</em> - The RUC make-whole amount to Market Participant $m$ for Operating Day $d$.</td>
</tr>
<tr>
<td>$\text{EqrRtMwp5minPrc}_{a,s,c}$</td>
<td>$$</td>
<td>Eligibility Period</td>
<td><em>RUC Electric Quarterly Reporting Make-Whole-Payment Amount per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period</em> - The RUC make-whole amount to AO $a$ for RUC Make-Whole-Payment Eligibility Period $c$ at Resource Settlement Location $s$ for use by AO $a$ in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>$\text{EqrRtMwp5minQty}_{a,s,c}$</td>
<td>$$</td>
<td>Eligibility Period</td>
<td><em>RUC Electric Quarterly Reporting Make-Whole-Payment Quantity per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period</em> - This value is set equal to 1 if $\text{EqrRtMwp5minPrc}_{a,s,c} &gt; 0$ for use by AO $a$ in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>$i$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$d$</td>
<td>An Operating Day.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$s$</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>$c$</td>
<td>none</td>
<td>none</td>
<td>A RUC Make-Whole-Payment Eligibility Period.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.10  RUC Make-Whole-Payment Distribution Amount

(1) A RTBM system-wide charge or credit\(^6\) will be calculated at each Settlement Location for each Asset Owner for each hour in order to fund the payments made under Section 4.5.9.8 to Resources committed by a local Transmission Operator to resolve a regional reliability issue. This system-wide amount will be determined by multiplying the system-wide Asset Owner deviations by a daily system-wide RTBM MWP rate. Additionally, a local charge will be calculated for Asset Owner within each Settlement Area in order to fund the payments made under Section 4.5.9.8 to Resources committed by SPP at the request of a local transmission operator or committed by a local transmission operator to solve a Local Reliability Issue. The local hourly amount will be determined by multiplying an Asset Owner’s RTBM actual load in the Settlement Area by a rate determined by the dividing the daily sum of all RUC make-whole-payments made under Section 4.5.9.8 to Resources committed to address a Local Reliability Issue in the Settlement Area by the daily sum of all Asset Owners’ RTBM actual load in the Settlement Area. A manual process is employed for the calculations and the charges will appear in the Miscellaneous Amount charge type defined in Section 4.5.11.

The system-wide charge hourly amount is calculated as follows:

\[
#RtMwpDistHrlyAmt_{a,s,h} = \text{RtMwpSppDistRate}_d \times \text{RtDevHrlyQty}_{a,s,h}
\]

Where,

(a) \[
\text{RtDevHrlyQty}_{a,s,h} = \text{RtNetSlDevHrlyQty}_{a,s,h} + \text{RtMinLimitDevHrlyQty}_{a,s,h} + \text{RtMaxLimitDevHrlyQty}_{a,s,h} + \text{RtOutageDevHrlyQty}_{a,s,h} + \text{RtStatusDevHrlyQty}_{a,s,h} + \text{RtRucScDevHrlyQty}_{a,s,h} + \text{RtRucCommitDevHrlyQty}_{a,s,h} + \text{RtURDDevHrlyQty}_{a,s,h}
\]

(a.1) An Asset Owner’s Settlement Location deviation is calculated as the Absolute Value of the sum of (1) (RTBM actual load MWh - DA Market cleared load MWh) – excluding deviations resulting from actual load consumption that is less than DA Market cleared load MWh during capacity shortage condition Emergencies, (2) (RTBM actual Export Interchange Transactions – DA Market cleared Export Interchange Transactions), (3) (RTBM actual Import Interchange Transactions – DA Market cleared Import Interchange Transactions), (4) (RTBM actual Through Interchange Transactions (sink only) – DA Market cleared Through Interchange Transactions (sink only)), (5) DA Market cleared Virtual

---

\(^6\) Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettlement.
Energy Bids * (-1), and (6) DA Market cleared Virtual Energy Offers * (-1). An Asset Owner’s Settlement Location deviation is calculated as follows.

\[ \text{RtNetSlDevHrlyQty}_{a,s,h} = \text{ABS} \sum_{i} \text{RtNetSlDev5minQty}_{a,s,i} \]

\[ \#\text{RtNetSlDev5minQty}_{a,s,i} = \]

\[ \left\{ \text{IF XmptDev5minFlg}_{a,s,i} = 0 \text{ THEN } 1 \text{ ELSE } 0 \right\} \times \left[ \text{Max} \left( 0, \text{RtBillMtr5minQty}_{a,s,i} \right) - \text{Max} \left( 0, \text{DaClrdHrlyQty}_{a,s,h} \right) \right] \]

\[ + \sum_{t} \left\{ \text{Max} \left( 0, \text{RtImpExp5minQty}_{a,s,i,t,dir} \right) \right\} - \text{Max} \left( 0, \text{DaImpExp5minQty}_{a,s,i,t,dir} \right) \]

\[ - \text{Max} \left( 0, \text{DaImpExp5minQty}_{a,s,i,t,dir} \right) \]

\[ + \text{IF DIR <> “THROUGH”, THEN} \]

\[ \text{Min} \left( 0, \text{RtImpExp5minQty}_{a,s,i,t,dir} \right) \]

\[ - \text{Min} \left( 0, \text{DaImpExp5minQty}_{a,s,i,t,dir} \right), \text{ELSE } 0 \} \}

\[ \times \left( 1 - \text{RsgCrdFlg}_{r} \right) \}

\[ - \sum_{t} \text{DaClrdVHrlyQty}_{a,s,h,t} \right\} / 12 \]

\[ \text{(a.2)} \] For a Resource with DA Market cleared MW in an hour the difference between the Resource’s applicable minimum limit and its DA Market cleared MW is included as a deviation if the Resource’s Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if cleared for Regulation-Up or Regulation-Down) in the RTBM is (1) greater than the comparable limits used to clear the Resource in the DA Market by more than the Resource Operating Tolerance except that, combined cycle Resources that were committed by SPP into a higher configuration in the RUC are excluded from this calculation; (2) is greater than its DA Market cleared MW; and (3) the Resource’s Dispatch Instruction in any Dispatch Interval within the Hour is less than or equal to the Resource’s applicable minimum limit, where the applicable minimum limit is equal to the Resource’s RTBM Minimum Economic Capacity Operating Limit if the Resource is not regulating or is equal to the sum of the Resource’s RTBM Minimum Regulation Capacity Operating Limit and the amount of Regulation-Down cleared on that Resource if the Resource is regulating. In the case where the Resource has cleared Regulation-Up or Regulation-Down in the RTBM and has not cleared Regulation-Up or Regulation-Down in the DA Market, the deviation is the lesser of (1)
the difference between the Resource’s RTBM regulation minimum limit and its DA Market cleared MW or (2) the difference between the Resource’s RTBM regulation minimum limit the its DA Market regulation minimum limit.

\[
\text{RtMinLimitDevHrlyQty}_{a,s,h} = \sum_{i} \text{RtMinLimitDev5minQty}_{a,s,i}
\]

Where,

\[
\text{IF DispInstrucMinHrlyFlg}_{a,s,h} = "1" \text{ AND DaClrdHrlyQty}_{a,s,h} < 0
\]

AND \text{RtRucComStat5minFlg}_{a,s,i,c} <> "1"

AND \text{RtRucComStat5minFlg}_{a,s,i,c} <> "0"

THEN

** Regulation is not cleared in RTBM **

\[
\text{IF ControlStatus5minFlg}_{a,s,i} <> "Regulating" \text{ AND}
\]

\[
( \text{RtDispMinEconCapOL5minQty}_{a,s,i} - \text{DaComMinEconCapOLHrlyQty}_{a,s,h} )
\]

\[
> \text{ResOpTol5minQty}_{a,s,i}
\]

THEN

\[
\text{#RtMinLimitDev5minQty}_{a,s,i} = \text{Max} \left( ( \text{RtDispMinEconCapOL5minQty}_{a,s,i} - \text{DaClrdHrlyQty}_{a,s,h} ), 0 \right) / 12
\]

ELSE IF

** Regulation is cleared in both DA Market and RTBM **

\[
\text{IF ControlStatus5minFlg}_{a,s,i} = "Regulating" \text{ AND}
\]

\[
\text{DaRegUpHrlyQty}_{a,z,s,h} + \text{DaRegDnHrlyQty}_{a,z,s,h} > 0 \text{ AND}
\]

\[
( \text{RtDispMinRegCapOL5minQty}_{a,s,i} - \text{DaComMinRegCapOLHrlyQty}_{a,s,h} )
\]

\[
> \text{ResOpTol5minQty}_{a,s,i}
\]

THEN

\[
\text{#RtMinLimitDev5minQty}_{a,s,i} =
\]
Max \{ ( \text{RtDispMinRegCapOL5minQty}_{a,s,i} + \text{DaClrdHrlyQty}_{a,s,h} ), 0 \} / 12

ELSE IF

**Regulation is cleared in RTBM and not cleared in DA Market**

IF ControlStatus5minFlg_{a,s,i} = “Regulating” AND

\text{DaRegUpHrlyQty}_{a,z,s,h} + \text{DaRegDnHrlyQty}_{a,z,s,h} = 0 AND

( \text{RtDispMinRegCapOL5minQty}_{a,s,i} - \text{DaComMinRegCapOLHrlyQty}_{a,s,h} ) > \text{ResOpTol5minQty}_{a,s,i}

THEN

#\text{RtMinLimitDev5minQty}_{a,s,i} =

Max \{ \text{RtDispMinRegCapOL5minQty}_{a,s,i} \\
- Max \{ \text{ABS} ( \text{DaClrdHrlyQty}_{a,s,h} ), \text{DaComMinRegCapOLHrlyQty}_{a,s,h} \}, 0 \} / 12

ELSE

\text{RtMinLimitDev5minQty}_{a,s,i} = 0

(a.3) For a Resource with DA Market cleared MW in an hour, the difference between the Resource’s DA Market cleared MW and its applicable maximum limit is included as a deviation if the Resource’s Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if cleared for Regulation-Up or Regulation-Down) in the RTBM is (1) less than the comparable limits used to clear the Resource in the DA Market by more than the Resource Operating Tolerance; (2) is less than its DA Market cleared MW; and (3) the Resource’s Dispatch Instruction in any Dispatch Interval within the Hour is greater than or equal to the Resource’s applicable maximum limit, where the applicable maximum limit is equal to the Resource’s RTBM Maximum Economic Capacity Operating Limit if the Resource is not regulating or is equal to the difference between the Resource’s RTBM Maximum Regulation Capacity Operating Limit and the amount of Regulation-Up cleared on that Resource if the Resource is regulating. In the case where the Resource has cleared Regulation-Up or Regulation-Down in the RTBM and has not cleared Regulation-Up or Regulation-Down in the DA Market, the deviation is the lesser of (1) the difference between the Resource’s DA Market cleared MW and its RTBM regulation maximum limit or (2) the difference between the Resource’s DA Market regulation maximum limit and its RTBM regulation maximum limit.
\[ \text{RtMaxLimitDevHrlyQty}_{a,s,h} = \sum_i \text{RtMaxLimitDev5minQty}_{a,s,i} \]

Where,

IF DispInstrucMaxHrlyFlg_{a,s,h} = “1” AND DaClrdHrlyQty_{a,s,h} < 0

THEN

** Regulation is not cleared in RTBM **

IF ControlStatus5minFlg_{a,s,i} <> “Regulating” AND

( DaComMaxEconCapOLHrlyQty_{a,s,h} - RtDispMaxEconCapOL5minQty_{a,s,i} ) > ResOpTol5minQty_{a,s,i}

THEN

#RtMaxLimitDev5minQty_{a,s,i} =

Max [ (ABS ( DaClrdHrlyQty_{a,s,h} ) - RtDispMaxEconCapOL5minQty_{a,s,i}), 0 ] / 12

ELSE IF

** Regulation is cleared in both DA Market and RTBM **

IF ControlStatus5minFlg_{a,s,i} = “Regulating” AND

DaRegUpHrlyQty_{a,z,s,h} + DaRegDnHrlyQty_{a,z,s,h} > 0 AND

( DaComMaxRegCapOLHrlyQty_{a,s,h} - RtDispMaxRegCapOL5minQty_{a,s,i} ) > ResOpTol5minQty_{a,s,i}

THEN

#RtMaxLimitDev5minQty_{a,s,i} =

Max [ (ABS ( DaClrdHrlyQty_{a,s,h} ) - RtDispMaxRegCapOL5minQty_{a,s,i}), 0 ] / 12

ELSE IF

** Regulation is cleared in RTBM and not cleared in DA Market **

IF ControlStatus5minFlg_{a,s,i} = “Regulating” AND
DaRegUpHrlyQty \_a, z, s, h + DaRegDnHrlyQty \_a, z, s, h = 0 \ AND

\( ( \text{DaComMaxRegCapOLHrlyQty} \_a, s, h - \text{RtDispMaxRegCapOL5minQty} \_a, s, i ) \)

> \text{ResOpTol5minQty} \_a, s, i

THEN

\#\text{RtMaxLimitDev5minQty} \_a, s, i =

\text{Max} \{ \text{Min} [ \text{ABS} ( \text{DaClrdHrlyQty} \_a, s, h ), \text{DaComMaxRegCapOLHrlyQty} \_a, s, h ]

- \text{RtDispMaxRegCapOL5minQty} \_a, s, i , 0 \} / 12

ELSE

\text{RtMaxLimitDev5minQty} \_a, s, i = 0

(a.4) For Resources with DA Market cleared MW in an hour, if the Resource is off-line in the RTBM and it has not been de-committed by SPP the Resource DA Market cleared MW is included as a deviation. An Asset Owner’s outage deviation is calculated as follows.

\text{RtOutageDevHrlyQty} \_a, s, h = \sum \text{RtOutageDev5minQty} \_a, s, i

IF \text{DaClrdHrlyQty} \_a, s, h < 0 \ AND

\text{RtBillMtr5minQty} \_a, s, i >= 0 \ AND

\text{ResDeCommit5minFlg} \_a, s, i <> “1”

THEN

\#\text{RtOutageDev5minQty} \_a, s, i = \text{ABS} ( \text{DaClrdHrlyQty} \_a, s, h ) / 12

ELSE

\text{RtOutageDev5minQty} \_a, s, i = 0

(a.5) For Resources with DA Market cleared MW in an hour, for each Dispatch Interval the Resource is in “Manual” status, a deviation is calculated that is equal to one-twelfth of the difference between the Resource actual output and the Resource’s Desired Dispatch. An Asset Owner’s status change deviation is calculated as follows.
RtStatusDevHrlyQty \( a,s,h = \sum_i \) \( \) RtStatusDev5minQty \( a,s,i \)

IF ControlStatus5minFlg \( a,s,i = \) “Manual” AND

DaClrdHrlyQty \( a,s,h < 0 \)

THEN

\#RtStatusDev5minQty \( a,s,i = \)

\[ \text{ABS} ( \text{RtBillMtr5minQty} \ a,s,i + \text{RtDispDesiredEn5minQty} \ a,s,i ) / 12 \]

ELSE

RtStatusDev5minQty \( a,s,i = 0 \)

(a.6) For Resources that Self-Committed following the Day-Ahead Market, including a combined cycle Resource that was committed in the DA Market and then Self-Committed into a higher configuration in RUC and the Resource’s Dispatch Instruction in any Dispatch Interval within the Hour is less than or equal to the Resource’s applicable minimum limit, a deviation is included in an amount equal to the Resource actual output. The applicable minimum limit is equal to the Resource’s RTBM Minimum Economic Capacity Operating Limit if the Resource is not regulating or is equal to the sum of the Resource’s RTBM Minimum Regulation Capacity Operating Limit and the amount of Regulation-Down cleared on that Resource if the Resource is regulating. Resources that were offered into the DA Market for SPP commitment and not committed in the DA Market and then Self-Committed prior to the Day-Ahead RUC are exempted from this calculation. An Asset Owner’s Self-Commit deviation is calculated as follows.

RtRucScDevHrlyQty \( a,s,h = \sum_i \) \( \) RtRucScDev5minQty \( a,s,i \)

IF RtRucComStat5minFlg \( a,s,i,c = \) “0” AND

DispInstrucMinHrlyFlg \( a,s,h = \) “1” AND

RtRucScDevXmpt5minFlg \( a,s,i <> \) “1”

THEN

\#RtRucScDev5minQty \( a,s,i = \)
ABS ( Min (RtBillMtr5minQty_{a,s,i} - DaClrdHrlyQty_{a,s,h}, 0) / 12 )

ELSE

RtRucScDev5minQty_{a,s,i} = 0

(a.7) For Resources that are either Self-Committed or committed by SPP following the DA Market and that are off-line in the RTBM and have not been de-committed by SPP, the greater of the Minimum Economic Capacity Operating Limit at the time of commitment or the Resource’s Desired Dispatch will be included as a deviation. An Asset Owner’s RTBM commitment outage deviation is calculated as follows.

\[ \text{RtRucCommitDevHrlyQty}_{a,s,h} = \sum_i \text{RtRucCommitDev5minQty}_{a,s,i} \]

IF \[ \text{RtRucComStat5minFlg}_{a,s,i,c} = \text{“0”} \text{ OR } \sum_i \text{RtBillMtr5minQty}_{a,s,i} \geq 0 \text{ AND } \text{ResDeCommit5minFlg}_{a,s,i} \neq 1 \] THEN

\[ \#\text{RtRucCommitDev5minQty}_{a,s,i} = \text{RtDesiredEn5minQty}_{a,s,i} / 12 \]

ELSE

RtRucCommitDev5minQty_{a,s,i} = 0

(a.8) In any Dispatch Interval in which a Resource operates outside of its Operating Tolerance and the Resource has not been exempted from URD per Section 4.4.4.1, one-twelfth of the Absolute Value of the Resource’s Uninstructed Resource Deviation is included as a deviation. An Asset Owner’s URD deviation is calculated as follows.

\[ \text{RtURDDevHrlyQty}_{a,s,h} = \sum_i \text{RtURDDev5minQty}_{a,s,i} \]

IF \[ \text{ABS (URD5minQty}_{a,s,i} ) > \text{ResOpTol5minQty}_{a,s,i} \] AND

( XmptDev5minFlg_{a,s,i} = 0 )
THEN

#RtURDDev5minQty\( a,s,i \) = \text{ABS}(\text{URD5minQty}\( a,s,i \)) / 12

ELSE

RtURDDev5minQty\( a,s,i \) = 0

(b) \#RtMwpSppDistRate\( d \) = 

\((\text{RtMwpSppDlyAmt}\( d \)/\text{RtDevSppDlyQty}\( d \)) \times (-1)\)

(b.1) \text{RtMwpSppDlyAmt}\( d \) = \sum\sum\text{RtMwpMpAmt}\( m,d \)

(b.2) \text{RtDevSppDlyQty}\( d \) = \sum\sum\sum\text{RtDevHrlyQty}\( a,s,h \)

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\text{RtMwpDistDlyAmt}\( a,s,d \) = \sum\text{RtMwpDistHrlyAmt}\( a,s,h \)

(3) For each Asset Owner associated with Market Participant\( m \), a daily amount is calculated. The daily amount is calculated as follows:

\text{RtMwpDistAoAmt}\( a,m,d \) = \sum\text{RtMwpDistDlyAmt}\( a,s,d \)

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\text{RtMwpDistMpAmt}\( m,d \) = \sum\text{RtMwpDistAoAmt}\( a,m,d \)
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtMwpDistHrlyAmt (_{a, s, h})</td>
<td>$</td>
<td>Hour</td>
<td>RUC Make-Whole-Payment Distribution Amount per AO per Hour per Settlement Location - The amount to AO (a) for Hour (h) and Settlement Location (s) for recovery of the total amount paid under Section 4.5.9.8 for Operating Day (d).</td>
</tr>
<tr>
<td>RtDevHrlyQty (_{a, s, h})</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Deviation Quantity per AO per Hour per Settlement Location – The total deviation MWh for AO (a) at Settlement Location (s) for Hour (h).</td>
</tr>
<tr>
<td>RtMwpSppDistRate (_d)</td>
<td>$/MWh</td>
<td>Operating Day</td>
<td>RUC Make-Whole Payment SPP Distribution Rate per Operating Day – The rate applied to AO (a)’s RtDevHrlyQty (_{a, s, h}) in each Hour (h) at Settlement Location (s) in Operating Day (d).</td>
</tr>
<tr>
<td>RtMwpMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Amount per MP per Operating Day - The value calculated under Section 4.5.9.8 for Operating Day (d).</td>
</tr>
<tr>
<td>RtMwpSppDlyAmt (_d)</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Amount per Operating Day - The SPP total of the values calculated under Section 4.5.9.8 for Operating Day (d).</td>
</tr>
<tr>
<td>RtDevSppDlyQty (_d)</td>
<td>MWh</td>
<td>Operating Day</td>
<td>Real-Time Deviation Quantity per Operating Day - The SPP total deviation MWh for all AOs for Operating Day (d).</td>
</tr>
<tr>
<td>RtNetSlDev5minQty (_{a, s, i})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Net Settlement Location Deviation per AO per Dispatch Interval per Settlement Location – AO (a)’s portion of RtDevHrlyQty (_{a, s, h}) related to net of Real-Time load deviations from Day-Ahead amount, Real-Time Interchange Transaction deviations from Day-Ahead amounts and virtual transactions at Settlement Location (s) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtNetSlDevHrlyQty (_{a, s, h})</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Net Settlement Location Deviation per AO per Hour per Settlement Location – The sum of AO (a)’s RtNetSlDev5minQty (_{a, s, i}) at Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
<td>RtBillMtr5minQty (_{a, s, i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The quantity described under Section 4.5.9.1.</td>
</tr>
</tbody>
</table>

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<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaClrdHrlyQty&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market – The quantity described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>RtImpExp5minQty&lt;sub&gt;a, s, i, t, dir&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval - The quantity described under Section 4.5.9.2 as identified by direction dir.</td>
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<tr>
<td>RsgCrdFlg&lt;sub&gt;t&lt;/sub&gt;</td>
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<td>none</td>
<td>Reserve Sharing Group Contingency Reserve Deployment Flag per Event – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>DaImpExp5minQty&lt;sub&gt;a, s, i, t, dir&lt;/sub&gt;</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval - The quantity described under Section 4.5.8.2 as identified by direction dir.</td>
</tr>
<tr>
<td>DaClrdVHrlyQty&lt;sub&gt;a, s, h, t&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Virtual Energy Quantity per AO per Settlement Location per Transaction per Hour in the DA Market – The quantity described under Section 4.5.8.3.</td>
</tr>
<tr>
<td>RtMinLimitDev5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Minimum Limit Deviation per AO per Dispatch Interval per Settlement Location – AO a’s portion of RtDevHrlyQty&lt;sub&gt;a, s, h&lt;/sub&gt; associated with Resources with cleared Day-Ahead amounts that increase their applicable minimum limit in Real-Time above their applicable minimum limit from the Day-Ahead Market commitment at Resource Settlement Location s in Hour h.</td>
</tr>
<tr>
<td>RtMinLimitDevHrlyQty&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Minimum Limit Deviation per AO per Hour per Settlement Location – The sum of AO a’s RtMinLimitDev5minQty&lt;sub&gt;a, s, i&lt;/sub&gt; at Resource Settlement Location s in Hour h.</td>
</tr>
<tr>
<td>RtMaxLimitDev5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Maximum Limit Deviation per AO per Dispatch Interval per Settlement Location – AO a’s portion of RtDevHrlyQty&lt;sub&gt;a, s, h&lt;/sub&gt; associated with Resources with cleared Day-Ahead amounts that reduce their applicable maximum limit in Real-Time below their applicable maximum limit from the Day-Ahead Market commitment at Resource Settlement Location s in Hour h.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>--------</td>
<td>---------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtMaxLimitDevHrlyQty(a, s, h)</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Maximum Limit Deviation per AO per Hour per Settlement Location – The sum of AO (a)'s (\text{RtMaxLimitDev5minQty})(a, s, i) at Resource Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
<td>RtOutageDev5minQty(a, s, i)</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Outage Deviation per AO per Dispatch Interval per Settlement Location – AO (a)'s portion of (\text{RtDevHrlyQty})(a, s, h) associated with Resources with cleared Day-Ahead amounts that are off-line in Real-Time and have not be de-committed by SPP at Resource Settlement Location (s) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtOutageDevHrlyQty(a, s, h)</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Outage Deviation per AO per Hour per Settlement Location – The sum of AO (a)'s (\text{RtOutageDev5minQty})(a, s, i) at Resource Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
<td>RtStatusDev5minQty(a, s, i)</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Resource Status Change Deviation per AO per Settlement Location per Dispatch Interval – AO (a)'s portion of (\text{RtDevHrlyQty})(a, s, h) associated with Resources for which the Control Status is set to “Manual” at Settlement Location (s) for Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtStatusDevHrlyQty(a, s, h)</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Status Deviation per AO per Hour per Settlement Location – The sum of AO (a)'s (\text{RtStatusDev5minQty})(a, s, i) at Resource Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
<td>ControlStatus5minFlg(a, s, i)</td>
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<td>Dispatch Interval</td>
<td>Control Status per AO per Settlement Location per Dispatch Interval – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>RtRucScDev5minQty(a, s, i)</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time RUC Self-Commit Deviation per AO per Settlement Location per Dispatch Interval – AO (a)'s portion of (\text{RtDevHrlyQty})(a, s, h) associated with Resources that have Self-Committed following completion of the Day-Ahead RUC process at Settlement Location (s) for Dispatch Interval (i).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>------------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtRucScDevXmpt5minFlg $a, s, i$</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>Real-Time RUC Self-Commit Deviation Exemption Flag per AO per Settlement Location per Dispatch Interval – a value of 1 for AO $a$’s Resources at Settlement Location $s$ for Dispatch Interval $i$ that were offered into the DA Market for SPP commitment and not committed in the DA Market and then Self-Committed prior to the Day-Ahead RUC, thus are exempted from Self-Commit deviation calculations.</td>
</tr>
<tr>
<td>RtRucScDevHrlyQty $a, s, h$</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time RUC Self-Commit Deviation per AO per Settlement Location per Hour – The summation of AO $a$’s $\text{RtRucScDev5minQty}_{a, s, i}$ for Hour $h$.</td>
</tr>
<tr>
<td>RtRucCommitDev5minQty $a, s, i$</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time RUC Commit Deviation per AO per Settlement Location per Dispatch Interval – AO $a$’s portion of $\text{RtDevHrlyQty}_{a, s, h}$ associated with Resources that were committed in the Day-Ahead RUC process and fail to come on line at Settlement Location $s$ for Dispatch Interval $i$.</td>
</tr>
<tr>
<td>RtRucCommitDevHrlyQty $a, s, h$</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time RUC Commit Deviation per AO per Settlement Location per Hour – The summation of AO $a$’s $\text{RtRucCommitDev5minQty}_{a, s, i}$ for Hour $h$.</td>
</tr>
<tr>
<td>RtURDDev5minQty $a, s, i$</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time URD Deviation per AO per Settlement Location per Dispatch Interval – AO $a$’s portion of $\text{RtDevHrlyQty}<em>{a, s, h}$ associated with Resources that have operated outside of their $\text{ResOpTol5minQty}</em>{a, s, i}$ at Settlement Location $s$ for Dispatch Interval $i$.</td>
</tr>
<tr>
<td>RtURDDevHrlyQty $a, s, h$</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time URD Deviation per AO per Hour per Settlement Location – The sum of AO $a$’s $\text{RtURDDev5minQty}_{a, s, i}$ at Resource Settlement Location $s$ in Hour $h$.</td>
</tr>
<tr>
<td>URD5minQty $a, s, i$</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation per AO per Settlement Location per Dispatch Interval – The value calculated as described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>XmptDev5minFlg $a, s, i$</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>Failure-to-Follow Dispatch Exemption Flag per AO per Resource Settlement Location per Dispatch Interval – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>---------------------------------</td>
<td>---------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>RtDispDesiredEn5minQty (a, s, i)</strong></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval – The value described under Section 4.5.9.9.</td>
</tr>
<tr>
<td><strong>RtDesiredEn5minQty (a, s, i)</strong></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td><strong>RtDispMinEconCapOL5minQty (a, s, i)</strong></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Minimum Economic Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The value described under Section 4.5.9.8 for Dispatch Interval (i).</td>
</tr>
<tr>
<td><strong>RtDispMinRegCapOL5minQty (a, s, i)</strong></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Minimum Regulation Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The value described under Section 4.5.9.8 for Dispatch Interval (i).</td>
</tr>
<tr>
<td><strong>DaComMinEconCapOLHrlyQty (a, s, h)</strong></td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Minimum Economic Capacity Operating Limit Quantity per AO per Settlement Location per Hour – The Minimum Economic Capacity Operating Limit associated with AO (a)'s eligible Resource at Settlement Location (s) for Hour (h) as submitted in the DA Market Offer used in the DA Market commitment decision.</td>
</tr>
<tr>
<td><strong>DaComMinRegCapOLHrlyQty (a, s, h)</strong></td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Minimum Regulation Capacity Operating Limit Quantity per AO per Settlement Location per Hour – The Minimum Regulation Capacity Operating Limit associated with AO (a)'s eligible Resource at Settlement Location (s) for Hour (h) as submitted in the DA Market Offer used in the DA Market commitment decision.</td>
</tr>
<tr>
<td><strong>RtDispMaxEconCapOL5minQty (a, s, i)</strong></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Maximum Economic Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Maximum Economic Capacity Operating Limit associated with AO (a)'s eligible Resource at Settlement Location (s) for Dispatch Interval (i).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>-------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtDispMaxRegCapOL5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Maximum Regulation Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Maximum Regulation Capacity Operating Limit associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i).</td>
</tr>
<tr>
<td>DaComMaxEconCapOLHrlyQty (_{a,s,h})</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Maximum Economic Capacity Operating Limit Quantity per AO per Settlement Location per Hour – The Maximum Economic Capacity Operating Limit associated with AO (a)’s eligible Resource at Settlement Location (s) for Hour (h) as submitted in the DA Market Offer used in the DA Market decision.</td>
</tr>
<tr>
<td>DaComMaxRegCapOLHrlyQty (_{a,s,h})</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Maximum Regulation Capacity Operating Limit Quantity per AO per Settlement Location per Hour – The Maximum Regulation Capacity Operating Limit associated with AO (a)’s eligible Resource at Settlement Location (s) for Hour (h) as submitted in the DA Market Offer used in the DA Market decision.</td>
</tr>
<tr>
<td>ResOpTol5minQty (_{a,s,i})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Resource Operating Tolerance per AO per Settlement Location per Hour – The value calculated as described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>ResDeCommit5minFlg (_{a,s,i})</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>Resource De-Commitment Flag per AO per Dispatch Interval per Settlement Location – A flag set by SPP indicating that AO (a)’s Resource has been de-committed by SPP at Resource Settlement Location (s) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtRucComStat5minFlg (_{a,s,i,c})</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>RUC Commitment Status Flag per AO per Resource Settlement Location per Dispatch Interval – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>DispInstrucMinHrlyFlg (_{a,s,h})</td>
<td>none</td>
<td>Hour</td>
<td>Dispatch Instruction Minimum Flag per AO per Hour per Settlement Location – A flag associated with AO (a)’s Resource that is set equal to “1” if the Resource receives a Dispatch Instruction that is less than or equal to the Resource’s applicable minimum limit at any time in Hour (h).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------------------------</td>
<td>----------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DispInstrucMaxHrlyFlg $a, s, h$</td>
<td>none</td>
<td>Hour</td>
<td>Dispatch Instruction Maximum Flag per AO per Hour per Settlement Location – A flag associated with AO $a$’s Resource that is set equal to “1” if the Resource receives a Dispatch Instruction that is greater than or equal to the Resource’s applicable maximum limit at any time in Hour $h$.</td>
</tr>
<tr>
<td>DaRegUpHrlyQty $a, z, s, h$</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Quantity per AO per Settlement Location per Hour – The value described under Section 4.5.8.4.</td>
</tr>
<tr>
<td>DaRegDnHrlyQty $a, z, s, h$</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Quantity per AO per Settlement Location per Hour – The value described under Section 4.5.8.5.</td>
</tr>
<tr>
<td>RtMwpDistDlyAmt $a, s, d$</td>
<td>S</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Distribution Amount per AO per Settlement Location per Operating Day - The amount to AO $a$ at Settlement Location $s$ for recovery of the total amount paid under Section 4.5.9.8 for Operating Day $d$.</td>
</tr>
<tr>
<td>RtMwpDistAoAmt $a, m, d$</td>
<td>S</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Distribution Amount per AO per Operating Day - The amount to AO $a$ associated with Market Participant $m$ for recovery of the total amounts paid under Section 4.5.9.8 for Operating Day $d$.</td>
</tr>
<tr>
<td>RtMwpDistMpAmt $m, d$</td>
<td>S</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Distribution Amount per MP per Operating Day - The amount to MP $m$ for recovery of the total amounts paid under Section 4.5.9.8 for Operating Day $d$.</td>
</tr>
</tbody>
</table>

$i$ none none An Dispatch Interval  
$h$ none none An Hour.  
$d$ none none An Operating Day.  
$a$ none none An Asset Owner.  
$c$ none none A RUC Make-Whole-Payment Eligibility Period.  
$s$ none None A Settlement Location.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$T$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Bilateral Settlement Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$\text{Dir}$</td>
<td>none</td>
<td>none</td>
<td>Direction (Import, Export or Through).</td>
</tr>
<tr>
<td>$M$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
6.1.7 Combined Cycle Resource

In addition to the responsibilities described under Section 6.1.1, Market Participants registering a Resource as a Combined Cycle Resource shall register their Resources for Commercial Modeling purposes using one of the three options described below.

1. Each combustion turbine and steam turbine may be registered as a separate Resource asset. Each individual Resource asset will be assigned a unique Settlement Location and each Resource asset must be registered to the same Asset Owner.

   a. Each Resource asset will be committed and dispatched as an independent Resource. Each individual Resource asset will be settled at its Settlement Location. Telemetering and Settlement meter data must be submitted for each registered Resource asset.

   b. The Market Participant may optionally request that all Resource assets be registered at a Common Bus.

2. An aggregate unit configuration may be registered as a single Resource asset in the Commercial Model and is assigned an APNode Settlement Location.

   a. The aggregate Resource asset will be committed and dispatched as a separate Resource and will be settled at its APNode Settlement location.

   b. Settlement meter data must be submitted for the aggregate Resource;

   c. Telemetering must be submitted for each component of the aggregate Resource that is modeled in the Network Model.

3. The Combined Cycle Resource may be registered in the Commercial Model as several “pseudo” unit assets, each unit representing a combination of one combustion turbine and a portion of a steam turbine. Each pseudo unit asset is assigned an APNode Settlement Location.

   a. Each pseudo unit asset will be committed and dispatched as a separate Resource and will be settled at its APNode Settlement location.

   b. Settlement meter data must be submitted for each individual pseudo unit asset.

   c. Telemetering must be submitted for each component - of each individual pseudo unit asset that is modeled in the Network Model.

   d. The Market Participant may optionally request that all pseudo unit assets be registered at a Common Bus.
(4) The combined cycle Resource may be registered as separate Resources, each representing a valid operating configuration.

(a) Market Participants using the combined cycle configuration based modeling option shall register the physical units that are part of the combined cycle resource as well as the logical operational configuration modes representing a “logical unit” of the combined cycle Resource. Each logical unit is treated as a separate Resource in the Commercial Model and may have Resource Offers submitted using the same Offer parameters as any other Resource. The physical unit data are referenced by the Network Model that needs detailed unit physical characteristics and parameters as inputs.

(b) Configuration Based modeling is only available for combined cycle Resources that can operate in more than one mode. SPP may limit the number of logical operational configurations that can be submitted per combined cycle Resource if needed to address software performance issues.

(c) Market Participants shall supply operating characteristics for each logical operational configuration of a combined cycle Resource, including, but not limited to: location of physical Resource, Legal owner, Resource type set to combined cycle (see section 6.1.1), and all of the non-price related operating parameters listed under Section 4.2.1.1 for each logical operational configuration;

(d) Market Participants shall define which operational configurations can be used when starting up or shutting down the combined cycle Resource. As an example, Exhibit 6-2 illustrates that the combined cycle Resource can only be started on configurations 1 and 3, while it can only be shutdown once it is operating in configuration 1 mode;

(e) Market Participants shall supply a state transition matrix for each logical operational configuration. The state transition matrix describes the state transition

<table>
<thead>
<tr>
<th></th>
<th>Configuration 1</th>
<th>Configuration 2</th>
<th>Configuration 3</th>
<th>Configuration 4</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Startup</strong></td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>(Yes/No):</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Shutdown</strong></td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>(Yes/No):</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
relationship between the individual logical operational configurations, and includes the following:

(i) **Transition Enabled**: a flag describing whether a configuration transition is allowed between two given configurations, in the direction of ‘From’ configuration towards ‘To’ configuration;

(ii) **Transition Cost**: the additional operational cost associated with a configuration transition, in the direction of ‘From’ configuration towards ‘To’ configuration;

(iii) **Transition Time**: the additional time needed to prepare for a configuration transition, in the direction of ‘From’ configuration towards ‘To’ configuration. During Transition Time, the Resource will not be eligible for clearing Operating Reserve;

Exhibit 6-3 provides an example of a state transition matrix for Transition Costs which indicates that switching to configuration 2 will result in a transition cost of $300.00, assuming the plant is operating in configuration 1 mode when the transition occurs.

### Exhibit 6-5: Combined Cycle Configuration Transition Cost Matrix

<table>
<thead>
<tr>
<th>From &gt; To</th>
<th>Configuration 1</th>
<th>Configuration 2</th>
<th>Configuration 3</th>
<th>Configuration 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Configuration 1</td>
<td>-</td>
<td>300</td>
<td>2,000</td>
<td>600</td>
</tr>
<tr>
<td>Configuration 2</td>
<td>0</td>
<td>-</td>
<td>1,500</td>
<td>3,000</td>
</tr>
<tr>
<td>Configuration 3</td>
<td>0</td>
<td>0</td>
<td>-</td>
<td>6,000</td>
</tr>
<tr>
<td>Configuration 4</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-</td>
</tr>
</tbody>
</table>

(f) **Market Participants** shall submit a Configuration Capability Array. The capability array stores information on the physical units that can participate in the operational state described by a logical operational configuration. Exhibit 6-4 provides a sample of a configuration capability array, where a ‘P’ represents a primary resource available for the configuration and an ‘A’ represents an alternate resource that can participate in the configuration.
Market Participants may optionally define groups of operational configurations to which a Group Minimum Run Time will apply. The Group Minimum Run Time, if defined, will be used in addition to the Plant Minimum Run Time for more accurate operational modeling of the plant. Exhibit 6-5 shows an example of how a group definition might be defined for a 2 x 1 plant. Configuration 1 is CT1, Configuration 2 is (CT1, ST), Configuration 3 is (CT2, ST) and Configuration 4 is (CT1, CT2, ST).

Exhibit 6-6 shows the impact of the use of Plant Minimum Run Time and Group Minimum Run Time on how the combined cycle plant is committed through various configurations.
Mitigation Measures for Transition State Offers

The mitigation measures in this section apply only to Resources registered using the combined cycle configuration based modeling option as described in Section 4.2.2.5.3(4). A Mitigated Transition State Offer shall be submitted daily by the Market Participant in accordance with the Mitigated Offer Development Guidelines for each potential transition state change. The Mitigated Transition State Offer may be updated up to 1100 hours on the day before the Operating Day for use in the DA Market. In the case a Resource in not committed by the Day-Ahead Market, the Mitigated Transition State Offer may be updated until the Day-Ahead RUC process begins. The Mitigated Transition State Offer submitted at the time the Day-Ahead RUC process begins will apply to the Day-Ahead RUC process on the day before the Operating Day and the Intra-Day RUC processes on the Operating Day.

The Transition State Offer threshold is a 25% increase above the Mitigated Transition State Offer.

The Transmission Provider shall apply mitigation measures by replacing the Transition State Offer with the applicable Mitigated Transition State Offer if:

1) The Resource’s Transition State Offer exceeds the applicable threshold; and
2) The Resource is subject to mitigation measures as determined in Section 8.2.2.2; and
3) The Resource fails the Market Impact Test as described in Section 8.2.2.8.
Appendix D - Settlement Metering Data Management Protocols

Real Time Data Reporting to SPP Balancing Authority

In addition to the data reporting requirements specified under SPP Criteria 7, all Resources, other than Demand Response Resources, are to submit the following data via ICCP to SPP.

(1) Unit power output (MW);
(2) Unit MVar output;
(3) Current on/off line status;
(4) Current AGC status (on/off).

Additionally, Resources that are registered under the combined cycle Resource configuration option in Section 4.2.2.5.3 (4) are required to submit the following information via ICCP to SPP:

(1) Unit power output for each physical individual component (with the exception of non-telemeterable pieces such as duct burners);
(2) The current configuration;
(3) Transition state status (in transition or not in transition).

Attachment AE

1.1 Definitions C

Commitment Instruction

An instruction issued by the Transmission Provider to a Market Participant to (i) either start up or shut down a specified Resource in the Day-Ahead Market or any Reliability Unit Commitment process and (ii) to transition from one configuration to another in the case of a combined cycle Resource that has been registered as described under in accordance with Section 4.1.2.2(4) of this Attachment AE.

1.1 Definitions G

Group Minimum Run Time
For a combined cycle Resource registered under the configuration-based option, the minimum length of time a defined group of configurations must run from the time the group is put online to the time the group is shut down.

1.1 Definitions M

**Mitigated Transition State Offer**

The compensation request by a Market Participant in a Mitigated Resource Offer representing the cost of moving a combined cycle Resource from its current configuration to another valid configuration. The mitigated compensation request in a Mitigated Resource Offer associated with a specific combined cycle Resource configuration, where such offers are developed in accordance with guidelines detailed in Appendix G of the Market Protocols, that represents the cost of moving from the current configuration to another valid configuration.

1.1 Definitions P

**Plant Minimum Run Time**

For a combined cycle Resource registered under the configuration-based option, the minimum length of time the combined cycle plant must run from the time the plant is committed to the time the plant is shut down.

1.1 Definitions R

**Resource Offer**

For a Resource, the combination of its Start-Up Offer, No-Load Offer, Energy Offer Curve, Transition State Offer, Regulation-Up Offer, Regulation-Down Offer, Spinning Reserve Offer, Supplemental Reserve Offer and Resource physical operating parameters.

1.1 Definitions T

**Transition State Offer**

An offer associated with a specific combined cycle Resource configuration that represents the cost of moving from the current configuration to another valid configuration.
**Transition State Time**

An operating parameter associated with a specific combined cycle Resource configuration that represents the time required to move from the current configuration to another valid configuration.

### 2.9 Combined Cycle Resource

Market Participants registering Resources with combined cycle capability as described in Section 4.1.2.2 of this Attachment AE shall select only one configuration modeling option during market registration. Market Participants that jointly participate in a combined cycle Resource that desire to use the Jointly Owned Unit modeling options described under Section 2.2(4) of this Attachment AE must register as a Jointly Owned Unit and cannot register the Resource as a combined cycle Resource. Modifications to combined cycle Resource configuration modeling options may be made in accordance with timing requirements defined in the Market Protocols.

### 4.1 Offer Submittal

Beginning seven (7) days prior to the Operating Day, Market Participants may begin to submit Offers for use in the Day-Ahead Market and Offers for use in the RTBM. Day-Ahead Market Offers may be updated up to 1100 hours Day-Ahead and RTBM Offers may be updated thirty (30) minutes prior to each Operating Hour. Offer submittals shall conform to the following:

1. Offers submitted in the Day-Ahead Market are independent from Offers submitted in the RTBM;
2. Market Participants may specify that the Offers submitted in the Day-Ahead Market also apply in the RTBM;
   - **Such an Offer shall be rejected in the RTBM if the Market Participant has submitted a Resource commitment status of “not participating” as described in Section 4.1(10)(e) of this Attachment AE and the Resource is not participating in the Day-Ahead Market.**
3. Submitted Resource Offers will automatically roll forward hour to hour until changed within each respective market;
(4) Offers may be submitted that vary for each hour of the Operating Day, except for the Offer parameters related to unit commitment as defined in the Market Protocols for which a single value is submitted. These unit commitment Offer parameters will automatically roll forward in each hour until updated;

(5) Offers submitted for use in the RTBM are also used in the RUC;

(6) Resource Offers may only be submitted at Resource Settlement Locations, Import Interchange Transaction Offers may only be submitted at External Interface Settlement Locations and Virtual Energy Offers may be submitted at any Settlement Location, including a Market Hub;

(7) For Regulation Qualified Resources and Regulation-Up Qualified Resources, Market Participants may submit Resource Offers for Regulation-Up, Spinning Reserve and Supplemental Reserve. For Regulation-Down Qualified Resources and Regulation Qualified Resources, Market Participants may submit Resource Offers for Regulation-Down. For Spin Qualified Resources, Market Participants may submit Resource Offers for Spinning Reserve and Supplemental Reserve. For Supplemental Qualified Resources, Market Participants may submit Resource Offers for Supplemental Reserve. Resource qualifications are verified by the Transmission Provider as part of the registration process as follows:

(a) A Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource must pass a specific regulation test as defined in Section 2.10.3 of this Attachment AE and must be capable of deploying one hundred percent (100%) of cleared Regulation-Up and/or Regulation-Down within the Regulation Response Time for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(b) A Spin Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Spinning Reserve or cleared Supplemental Reserve within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.
(c) A Supplemental Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Supplemental Reserve from an off-line state within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(8) Resource Offers are limited by the Offer caps and floors specified in Section 4.1.1 of this Attachment AE;

(9) The Resource Offer parameters that constitute a valid Offer for use in either the Day-Ahead Market or RTBM are submitted using the data formats, procedures, and information defined in the Market Protocols and will include the following (as further defined in the Market Protocols):

- Resource Name
- Resource Type
- Start-up Offer
- No-Load Offer
- **Energy Offer Curve**
- **Transition State Offer**
  - **Transition State Time**
  - Regulation–Up and Regulation-Down Offers
  - Spinning and Supplemental Reserve Offers
  - Sync-To-Min and Min-To-Off Times
  - Start-Up Time
  - Hot to Intermediate and Hot to Cold Times
  - Maximum Daily and Weekly Starts
  - Maximum Daily Energy
- **Maximum and Minimum Run Times**
  - **Plant Minimum Run Time (combined cycle only)**
  - **Group Minimum Run Time (combined cycle only)**
  - Minimum Down Time
• Minimum Emergency Capacity Operating Limit and Run Time
• Minimum Normal, Economic, and Regulation Capacity Operating Limits
• Maximum Normal, Economic, and Regulation Capacity Operating Limits
• Maximum Emergency Capacity Operating Limits and Run Time
• Maximum Quick-Start Response Limit
• Ramp-Rate-Up and Ramp-Rate-Down
• Turn-Around Ramp Rate Factor
• Regulation Ramp Rate
• Contingency Reserve Ramp Rate
• Resource Status

  ____JOU Ownership Share

  • Mitigated Transition State Offer (combined cycle only)

(10) Market Participants must specify a Resource commitment status as part of the Resource Offer using the data formats, procedures, and information defined in the Market Protocols. Market Participants use the commitment status to indicate:

  (a) Whether they are self-committing a Resource;
  (b) Whether the Resource may be committed by the Transmission Provider;
  (c) Whether the Resource may be committed by the Transmission Provider only to alleviate an anticipated Emergency Condition or local reliability issue; or
  (d) Whether the Resource is unavailable.

(11) Market Participants must specify a Resource dispatch status as part of the Resource Offer using the data formats, procedures and information defined in the Market Protocols. Market Participants use the dispatch status to notify the Transmission Provider whether the Resource is:

  (a) Eligible for Energy Dispatch;
  (b) Eligible for Operating Reserve clearing; or
  (c) Self-scheduled for Operating Reserve.

(12) Resource limits submitted as part of the Resource Offer must pass the validation rules defined in the Market Protocols, otherwise, the Resource Offer will be rejected; and
The Market Participant must comply with the must-offer requirements as defined in Section 2.11 of this Attachment AE.

### 4.1.2.2 Combined Cycle Resource

Market Participants shall select from one of the following options regarding submitting Resource Offers for their registered combined cycle Resources, which will be declared during asset registration as described under Sections 2.2 and 2.9 of this Attachment AE:

1. A Resource Offer may be submitted for a single aggregate combined cycle Resource, where the aggregate will represent a Market Participant selected operating configuration of combustion turbines and steam turbines. Under this option, the combined cycle Resource will be committed, dispatched and settled the same as any other Resource; or

2. A Resource Offer may be submitted for each combined cycle Resource combustion turbine and/or steam turbine and each component will be committed and dispatched independently and settled the same as any other single Resource; or

3. A Resource Offer may be submitted for each pseudo combined cycle Resource, where each pseudo combined cycle Resource will represent the combination of one combustion turbine and a portion of the steam turbine. Under this option, each pseudo combined cycle Resource must be capable of being committed and dispatched independently the same as any other Resource and each pseudo combined cycle Resource will be settled the same as any other Resource; or

4. A Resource Offer may be submitted for multiple combined cycle configurations, with each configuration being treated as a separate Resource. Under this option, Market Participants must define valid configurations during asset registration, including valid start-up and shutdown configurations and valid transitions between configurations as defined in the Market Protocols. The Transmission Provider will determine the most economic commitment configuration, if requested to
do so by the Market Participant as part of the submitted Resource Offer, and, once committed, the most economic configuration to transition to on an hourly basis for use in both the Day-Ahead Market and Real-Time Balancing Market. Each valid combined cycle Resource configuration will be committed and dispatched and/or transitioned and dispatched the same as any other Resource. Settlement for a combined cycle Resource and settlement will occur in the same manner as any other Resource except that Transition State Offer costs will also be eligible for recovery as described under Section 8.6.5 of this Attachment AE.

5.1.2 Day-Ahead Market Execution

The Transmission Provider will employ a simultaneous co-optimization methodology to perform the following tasks in order to clear the Day-Ahead Market for each hour of the upcoming Operating Day:

1. Commit Offered Resources, Import Interchange Transaction Offers and Virtual Energy Offers using the SCUC algorithm to meet the Demand Bids, Virtual Energy Bids, Export Interchange Transactions Bids and Operating Reserve requirements on a least cost basis for each hour of the upcoming Operating Day.

   a. The Day-Ahead Market SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, including Resources committed in the Multi-Day Reliability Assessment, up to the Resources’ Maximum Economic Capacity Operating Limit or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up, and down to the Resources’ Minimum Economic Capacity Operating Limit or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down. In addition, combined cycle Resources that were registered consistent with the offer submission option described under Section 4.1.2.2(4) of this Attachment AE are not eligible for regulation selection in any hour in which they are transitioning from one between configurations to another.
(i) If this capacity is not sufficient to meet the fixed Demand Bids and fixed Export Interchange Transaction Bids plus Operating Reserve requirements on a system-wide basis, the Day-Ahead Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

(ii) If there is a capacity surplus on a system-wide basis calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transaction Offers and the Regulation-Down requirement that is in excess of the sum of fixed Demand Bids and fixed Export Interchange Transaction Bids, the Day-Ahead Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; and (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limits until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement.

(b) To the extent that a particular reliability issue cannot be directly addressed within the Day-Ahead Market SCUC algorithm as described under Subsections (i) and (ii) above, the Transmission Provider may manually commit Resources to alleviate such reliability issues. The Transmission Provider will re-run the Day-Ahead SCUC algorithm after such manual commitments, time permitting, and will notify the Market Participants that units were manually committed.

(2) Using the Resource commitment results from the SCUC, clear Resource Offers, Virtual Energy Offers and Import Interchange Transaction Offers to meet
Demand Bids, Virtual Energy Bids, Export Interchange Transaction Bids and Operating Reserve requirements on a least cost basis for each hour of the upcoming Operating Day using the SCED algorithm.

(a) The SCED algorithm includes marginal loss sensitivity factors that approximate the change in marginal system losses for a change in Energy dispatch.

(b) In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, the Transmission Provider must apply VRLs in SCED as described in Section 8.3.2 of this Attachment AE.

(c) The SCED algorithm will include product substitution logic as follows to clear Operating Reserve Offers:

(i) Any Regulation-Up Offers remaining once the Regulation-Up Requirement is satisfied may be used to meet Contingency Reserve requirements if Regulation-Up Offer is more economic or is required to meet the overall Operating Reserve requirement;

(ii) Any Spinning Reserve Offers remaining once the Spinning Reserve Requirement is satisfied may be used to meet Supplemental Reserve requirements if Spinning Reserve Offer is more economic or is required to meet the overall Operating Reserve requirement; and

(iii) The product substitution logic ensures that the MCP for Regulation-Up is always greater than or equal to the Spinning Reserve MCP and that the Spinning Reserve MCP is always greater than or equal to the Supplemental Reserve MCP.

(d) Use of co-optimization logic will provide, through the Shadow Price calculation, MCPs for Operating Reserve that include any lost opportunity costs incurred as a result of Operating Reserve clearing.

(e) Combined cycle Resources that are registered consistent with the offer submission option described under Section 4.1.2.2(4) of this Attachment AE with Transition State Times greater than 30 minutes are
not eligible to clear Contingency Reserve in any hour in which they are transitioning between configurations.

5.2.2 Day-Ahead Reliability Unit Commitment Execution

The Transmission Provider will perform a capacity adequacy analysis for the upcoming Operating Day using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider load forecast and Operating Reserve requirements over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined in the submitted Energy Offer Curve.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, up to the Resources’ Maximum Economic Capacity Operating Limit or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up, and down to the Resources’ Minimum Economic Capacity Operating Limit or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down. In addition, combined cycle Resources that are registered consistent with the offer submission option described under Section 4.1.2.2(4) of this Attachment AE are not eligible for regulation selection in any hour in which they are transitioning from one configuration to another.

(a) If this capacity is not sufficient on a system-wide basis to meet the Transmission Provider load forecast plus Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this
Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement.

(b) If there is a capacity surplus on a system-wide basis calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transaction Offers and the Regulation-Down requirement that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transaction Bids, the SCUC algorithm will, in priority order:

1. curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated;
2. incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limits until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement;
3. de-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and
4. de-commit self-committed Resources until the capacity surplus is eliminated.

(3) To the extent that a particular Transmission System security constraint cannot be directly addressed within the SCUC algorithm, the Transmission Provider may manually commit Resources and/or decommit Resources, including self-committed Resources to alleviate such a Transmission System security constraint in accordance with its authority as Reliability Coordinator.

(a) A reliability issue may arise within the operating area of a local transmission operator during the Day-Ahead Reliability Unit Commitment process. Such reliability issues may require out of merit commitment, decommitment, or dispatch instructions to be issued to one or more Resources to resolve the reliability issue. In such cases, the local transmission operator shall request the Transmission Provider to issue such instructions. To the extent that the Transmission Provider, at the request of a local transmission operator, issues instructions to a Resource to address a reliability issue, such Resource shall be eligible for compensation in the same manner as any other Resource. Recovery of
such compensation shall be collected regionally as described under Section 8.6.7(A) of this Attachment AE, unless the Transmission Provider determines that the instructions were required for a Local Reliability Issue; in such case recovery of such compensation shall be collected locally as described under Section 8.6.7(B) of this Attachment AE.

5.2.3 Day-Ahead Reliability Unit Commitment Results

No later than 2000 hours or three (3) hours following the start of the Day-Ahead RUC, whichever is later, the Transmission Provider shall communicate the following results to Market Participants. The Transmission Provider will update the Current Operating Plan, if needed, and issue start-up and/or shut-down orders simultaneously, which may occur anytime after 2000 hours. The Day-Ahead RUC results include:

(1) For any future hours in which the Transmission Provider anticipates an emergency situation, the Transmission Provider shall notify all Market Participants identifying: the hours in which the emergency capacity of any Resources are expected to be required; the hours in which Resources are identified for reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, are expected to be committed; the hours in which non-firm fixed Export Interchange Transactions are expected to be curtailed; and the hours in which non-firm fixed Import Interchange Transactions are expected to be curtailed.

(a) Affected Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than thirty (30) minutes prior to the beginning of the Operating Hour that the Maximum Emergency Capacity Operating Limit will be used; and

(b) Affected Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than thirty (30) minutes prior to the beginning of the Operating Hour that the Minimum Emergency Capacity Operating Limit will be used.

(2) Using the results from the Day-Ahead RUC analysis, the Transmission Provider will update the Current Operating Plan and will issue start-up and shut-down
orders as appropriate. The Transmission Provider can only de-commit Day-Ahead Market committed Resources or move a Day-Ahead Market committed combined cycle Resource submitting configuration based offers as described under Section 4.1.2.2(4) of this Attachment AE from a higher capacity configuration to a lower capacity configuration to address an anticipated excess supply condition as described under Section 5.2.2(2)(b) of this Attachment AE and/or to address any other Emergency conditions. If the Transmission Provider de-commits a Transmission Provider committed Resource or moves a combined cycle resource from a higher capacity configuration to a lower capacity configuration for any hour of the Day Market commitment schedule, and causes the Resource to buy back its Energy and/or Operating Reserve position at RTBM prices that exceed the Day Ahead Market prices for the comparable products, that Resource is eligible for compensation under Section 8.6.6(2) of this Attachment AE.

6.1.2 Intra-Day Reliability Unit Commitment Execution

Using the inputs described in Section 6.1.1, the Transmission Provider will perform a capacity adequacy analysis using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider’s load forecast and Operating Reserve requirements over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined on the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the SCUC in making commitment decisions.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, only including capacity up to the Resources’ Maximum
Economic Capacity Operating Limits (or Maximum Regulation Capacity Operating Limits if selected for Regulation-Up) and down to the Resources’ Minimum Economic Capacity Operating Limits (or Minimum Regulation Capacity Operating Limits if selected for Regulation-Down). In addition, combined cycle Resources that were registered consistent with the offer submission option described under Section 4.1.2.2(4) of this Attachment AE are not eligible for regulation selection in any hour in which they are transitioning from one between configurations to another.

(a) If this capacity is not sufficient on a system-wide basis to meet the Transmission Provider’s load forecast plus Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement.

(b) If there is a system-wide capacity surplus calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transaction Offers and the Regulation-Down requirement that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transaction Bids, the Day-Ahead Market SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) Incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limits until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement; (3) De-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and (4) De-commit self-committed Resources until the capacity surplus is eliminated.
(3) To the extent that a particular reliability issue cannot be directly addressed within the SCUC algorithm as described under subsections (a) and (b) above, the Transmission Provider or local transmission operator may manually commit Resources and/or decommit Resources, including self-committed Resources to alleviate such reliability issues.

(4) A Local Reliability Issue may arise within the operating area of a local transmission operator during the Intra-Day Reliability Unit Commitment Process. Such Local Reliability Issues may require out of merit commitment, decommitment, or dispatch instructions to be issued to one or more Resources to resolve the Local Reliability Issue. Time permitting, the local transmission operator shall request the Transmission Provider to issue such instructions. To the extent time does not permit, the local transmission operator may issue such instructions to the Resource. In such cases, the following shall take place:

(a) If initial instructions are issued by a local transmission operator, the transmission operator shall notify the Transmission Provider of the instructions given to the Resource.

(b) The transmission operator and Transmission Provider will coordinate to ensure subsequent instructions are provided by the Transmission Provider.

(c) The transmission operator shall log such instructions, and shall notify the Transmission Provider of such action. The Transmission Provider shall log such instructions as manual commitment, decommitment, or OOME Dispatch instruction, as appropriate, as if it gave such instruction to the Resource.

(d) The Resource shall be eligible to receive the compensation for such instructions in the same manner as if it had been committed by the Transmission Provider; provided that the Transmission Provider determines that the Resource selected in response to such instructions was selected in a non-discriminatory manner. Such determination shall be made using the standards and procedures set forth in Section 6.1.2.1 of this Attachment AE. If the Transmission Provider determines that instructions were issued to resolve a Local Reliability Issue, recovery of
such compensation shall be collected locally as described under Section 8.6.7(B) of this Attachment AE.

(5) In the event that the local transmission operator issues instructions to a Resource to resolve an issue other than a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by the Transmission Provider; provided that the Transmission Provider determines that the Resource selected in response to such instructions was selected in a non-discriminatory manner. Such determination shall be made using the standards and procedures set forth in Section 6.1.2.1 of this Attachment AE. Recovery of such compensation shall be collected regionally as described under Section 8.6.7(A) of this Attachment AE.

(6) In the event that the Transmission Provider issues instructions to a Resource at the request of a local transmission operator to resolve a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by the Transmission Provider. Recovery of such compensation shall be collected locally as described under Section 8.6.7(B) of this Attachment AE.

(7) In the event that the Transmission Provider issues instructions to a Resource at the request of a local transmission operator to resolve an issue other than a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by the Transmission Provider. Recovery of such compensation shall be collected regionally as described under Section 8.6.7(A) of this Attachment AE.

6.1.3 Intra-Day Reliability Unit Commitment Results

The Transmission Provider will electronically communicate the Intra-Day RUC results for each hour of the Operating Day to Market Participants following completion of each Intra-Day RUC execution. The results consist of the following:

(1) For any future hours in which the Transmission Provider anticipates an Emergency situation, SPP shall notify all Market Participants identifying: the hours in which the emergency ranges of any Resources are expected to be required; the hours in which identified or reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, are expected to be committed; the
hours in which non-firm fixed Export Interchange Transactions are expected to be curtailed; and the hours in which non-firm fixed Import Interchange Transactions are expected to be curtailed.

(a) Affected Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than thirty (30) minutes prior to the beginning of the Operating Hour that the Maximum Emergency Capacity Operating Limit will be used; and

(b) Affected Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than thirty (30) minutes prior to the beginning of the Operating Hour that the Minimum Emergency Capacity Operating Limit will be used.

(2) Using the results from the Intra-Day RUC, the Transmission Provider will update the Current Operating Plan and will issue start-up and shut-down orders as appropriate. The Transmission Provider can only de-commit a Transmission Provider committed Day-Ahead Market Resource or move a Day-Ahead Market committed combined cycle Resource submitting configuration based offers as described under Section 4.1.2.2(4) of this Attachment AE from a higher capacity configuration to a lower capacity configuration to address an anticipated excess supply condition as described under Section 6.1.2(2)(b) of this Attachment AE and/or to address any other Emergency conditions. If the Transmission Provider de-commits a Transmission Provider committed Resource or moves a combined cycle resource from a higher capacity configuration to a lower capacity configuration for any hour of the Day-Ahead Market commitment schedule and causes that the Resource to buy back its Energy and/or Operating Reserve position at RTBM prices that exceed the Day-Ahead Market prices for the comparable products, that Resource is eligible for compensation under Section 8.6.6(2) of this Attachment AE.
8.5.9 Day-Ahead Make Whole Payment Amount

(1) The Day-Ahead make whole payment amount is a payment to an Asset Owner and is calculated for each Resource with an associated Day-Ahead Market Commitment Period that was committed by the Transmission Provider with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(b) and (c) of this Attachment AE, or was committed as part of the Multi-Day Reliability Assessment as defined under Section 4.5.3 of this Attachment AE. A payment is made to the Asset Owner when the sum of the Resource’s costs is greater than the Day-Ahead Market revenues received for that Resource over the Resource’s Day-Ahead Market make whole payment eligibility period. The make whole payment is equal to this difference between these costs and revenues.

(2) A Resource’s Day-Ahead Market make whole payment eligibility period is equal to a Resource’s Day-Ahead Market Commitment Period except as defined herein. For Resources with an associated Day-Ahead Market Commitment Period that begins in one Operating Day and ends in the next Operating Day, two (2) Day-Ahead Market make whole payment eligibility periods are created. The first period begins in the first Operating Day in the hour that the Day-Ahead Market Commitment Period begins and ends in the last hour of the first Operating Day. The second period begins in the first hour of the next Operating Day and ends in the last hour of the Day-Ahead Market Commitment Period.

(3) The following cost recovery rules apply to each Day-Ahead Market make whole payment eligibility period. Offer costs are calculated using the Day-Ahead Market Offer prices in effect at the time the commitment decision was made except under the situation described under Section (b)(i) below.

(a) There may be more than one Day-Ahead Market make whole payment eligibility period for a Resource in a single Operating Day for which a charge or payment is calculated. A single Day-Ahead Market make whole payment eligibility period is contained within a single Operating Day.
(b) A Resource’s Day-Ahead Market Start-Up Offer costs are not eligible for recovery in the following Day-Ahead Market make whole payment eligibility periods:

(i) For any Day-Ahead Market make whole payment eligibility period that is adjacent to the end of a RUC make whole payment eligibility period except as described under Section 8.6.5(3)(h);

(ii) For any Day-Ahead Market make whole payment eligibility period resulting from a Day-Ahead Market Commitment Period that contains a Day-Ahead Market self-commit hour; or

(iii) For any Day-Ahead make whole payment eligibility period for which a Resource is a Synchronized Resource prior to this commitment period at a time one (1) hour prior to that Resource’s Day-Ahead Market Commit Time less the Resource’s Sync-To-MinTime.

(c) For each Day-Ahead Market make whole payment eligibility period within an Operating Day, a Resource’s Day-Ahead Market Start-Up Offer is divided by the lesser of (1) the Resource’s Minimum Run Time rounded down to the nearest hour or (2) twenty-four (24) hours, and that portion of the Start-Up Offer is included as a cost in each hour of the Day-Ahead Market make whole payment eligibility period until the sum of these hourly costs are equal to the Day-Ahead Market Start-Up Offer or until the end of the Day-Ahead Market make whole payment eligibility period, whichever occurs first.

(d) To the extent that the full amount of the Day-Ahead Market Start-Up Offer is not accounted for in the last Day-Ahead Market make whole payment eligibility period in the Operating Day, any remaining Day-Ahead Market Start-Up Offer costs are carried forward for recovery in the first Day-Ahead Market make whole payment eligibility period of the following Operating Day.
The payment to each Asset Owner for each eligible Settlement Location for a given Day-Ahead Market make whole payment eligibility period is calculated as follows:

Day-Ahead Make Whole Payment Amount =
Maximum of [Either Zero or Sum of ((Day-Ahead Make Whole Payment Cost Amount in the Day-Ahead Market Make Whole Payment Eligibility Period) + (Day-Ahead Make Whole Payment Revenue Amount in the Day-Ahead Market Make Whole Payment Eligibility Period))] * (-1)

(a) An Asset Owner’s Day-Ahead Make Whole Payment Cost Amount for each eligible Resource is equal the sum for all hours in the Day-Ahead Market Make Whole Payment Eligibility Period of:

(i) Day-Ahead Market Start-Up Offer,
(ii) Day-Ahead Market No-Load Offer,
(iii) Day-Ahead Transition State Offer,
(iv) Energy cost associated with cleared Resource Energy from Resource Energy Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Resource Energy by the cost of such Energy as calculated from the Resource’s Day-Ahead Market Energy Offer Curve,
(iv) Regulation-Up cost associated with cleared Regulation-Up from Regulation-Up Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying Regulation-Up by the cost of such Regulation-Up as calculated from the Resource’s Day-Ahead Market Regulation-Up Offer,
(vi) Regulation-Down cost, associated with cleared Regulation-Down from Regulation-Down Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying Regulation-Down by the cost of such Regulation-Down as calculated from the Resource’s Day-Ahead Market Regulation-Down Offer,
(vii) Spinning Reserve cost, associated with cleared Spinning Reserve from Spinning Reserve Offers as described under Section 5.1.3 of
this Attachment AE, as calculated by multiplying Spinning Reserve by the cost of such Spinning Reserve as calculated from the Resource’s Day-Ahead Market Spinning Reserve Offer, and

(viii) Supplemental Reserve cost, associated with cleared Supplemental Reserve from Supplemental Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying Supplemental Reserve by the cost of such Supplemental Reserve as calculated from the Resource’s Day-Ahead Market Supplemental Reserve Offer.

(ix) For combined cycle Resources that are registered in accordance consistent with the offer submission option described under Section 4.1.2.2(4) of this Attachment AE, additional costs associated with situations in which the Resource has cleared Contingency Reserve in the Day-Ahead Market and must buy back that position in Real-Time at an average hourly Real-Time MCP that is greater than the Day-Ahead MCP, the Market Participant may be eligible for a make-whole payment if such costs are not otherwise eligible for recovery under Section 8.6.5 of this Attachment AE. To be eligible, these costs must be incurred during time periods in which the Resource is transitioning between configurations, at the direction of the Transmission Provider, and such cost is not due to any independent action of the Market Participant. In such cases, the additional costs are equal to the difference between the average hourly Real-Time MCP and the Day-Ahead MCP multiplied by the Day-Ahead Market cleared Contingency Reserve MW amounts. Recovery of these costs is limited to the time period defined as the Transition State Time submitted in the Resource Offer.
(b) An Asset Owner’s Day-Ahead Make Whole Payment Revenue Amount for each eligible Resource is equal to the sum for all hours in the Day-Ahead Market Make Whole Payment Eligibility Period of:

(i) Energy revenue associated with cleared Resource Energy from Resource Energy Offers as described under Section 5.1.3 of this Attachment AE, calculated by multiplying Resource Energy by Day-Ahead LMP at that Resource Settlement Location, and

(ii) The sum of the revenues calculated under Section 8.5.2, 8.5.3 and 8.5.4 for that eligible Resource.

8.6.5 Reliability Unit Commitment Make Whole Payment Amount

(1) Asset Owners of Resources committed by the Transmission Provider with an RTBM Resource Offer commitment status as defined under Sections 4.1(10)(b) and (c) of this Attachment AE or committed by a local transmission operator that the Transmission Provider determines were selected in a non-discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, are eligible to receive a RUC make whole payment. A RUC make whole payment is made to the Asset Owner when the sum of a Resource’s eligible RTBM Start-Up Offer costs, No-Load Offer costs, Transition State Offer costs, Energy Offer Curve and Operating Reserve Offer costs associated with actual Energy and cleared RTBM Operating Reserve is greater than the Energy and Operating Reserve RTBM revenues received over the Resource’s RUC make whole payment eligibility period. Recovery of such compensation shall be collected in accordance with Section 8.6.7 of this Attachment AE. Resources that are committed by a local transmission operator that the Transmission Provider determines were selected in a discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, are not eligible to receive a RUC make whole payment.

(2) A Resource’s RUC make whole payment eligibility period is equal to that Resource’s RUC Commitment Period except that unless...
(a) For Resources with a RUC Commitment Period that begins in one Operating Day and ends in the next Operating Day, two RUC make whole payment eligibility periods are created. The first period begins in the first Operating Day in the Dispatch Interval associated with the Resource’s RUC Commit Time and ends at the last Dispatch Interval of the first Operating Day. The second period begins in the first Dispatch Interval of the next Operating Day and ends in the Dispatch Interval associated with the Resource’s RUC De-Commit Time; or

(b) For combined cycle Resource’s that were registered consistent in accordance with the offer submission option described under Section 4.1.2.2.(4) of this Attachment AE that cleared in the Day-Ahead Market and that were transitioned by the Transmission Provider into a different configuration in Real-Time, that Resource’s RUC make-whole payment eligibility period that (i) begins in the first Dispatch Interval for the hour in which the transition to the selected configuration is to be completed, as calculated based upon when the Transmission Provider issues the order to transition and the Resource’s Transition State Time, and (ii) ends in the Dispatch Interval in which the Transmission Provider issues an order to transition to same configuration used in the Day-Ahead Market clearing, or the Dispatch Interval in which the combined cycle Resource no longer has Day-Ahead Market cleared MWs or the end of the Operating Day, whichever is less earliest.

(3) The following cost recovery rules apply to each RUC make whole payment eligibility period. Offer costs are calculated using the RTBM Offer prices in effect at the time the commitment decision was made.

(a) If the Transmission Provider cancels a Commitment Instruction prior to the start of the associated RUC make whole payment eligibility period and the Resource is not a Synchronized Resource, the Asset Owner will receive reimbursement for a time-based pro-rata share of the Resource’s RTBM Start-Up Offer. Asset Owners may request additional compensation through submittal of actual cost documentation to the
Transmission Provider. The Transmission Provider will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

(b) In order to receive the full amount of Start-Up Offer recovery within a RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in at least one Dispatch Interval in the RUC make whole payment eligibility period.

(c) In order to receive recovery of No-Load Offer costs in any Dispatch Interval in the RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in that Dispatch Interval.

(d) There may be more than one RUC make whole payment eligibility period for a Resource in a single Operating Day. A single RUC make whole payment eligibility period is contained within a single Operating Day.

(e) A Resource’s RTBM Start-Up Offer costs are not eligible for recovery in the following RUC make whole payment eligibility periods:

(i) Any RUC make whole payment eligibility period that is adjacent to the end of a Day-Ahead Market make whole payment eligibility period;

(ii) Any RUC make whole payment eligibility period for which a Resource is a Synchronized Resource prior to this commitment period at a time one (1) hour prior to that Resource’s RUC Commit Time less the Resource’s Sync-To-Min Time; and

(iii) Any RUC make whole payment eligibility period resulting from a RUC Commitment Period that contains an hour for which the Resource was self-committed.

(f) For each RUC make whole payment eligibility period within an Operating Day, a Resource’s RTBM Start-Up Offer is divided by the lesser of (1) the Resource’s Minimum Run Time multiplied by twelve (12), rounded down to the nearest whole interval, or (2) twenty-four (24) hours multiplied by twelve (12), and that portion of the Start-Up Offer is included as a cost in
each interval of the RUC make whole payment eligibility period until the
sum of these interval costs are equal to the RTBM Start-Up Offer or until
the end of the RUC make whole payment eligibility period, whichever
occurs first.

(g) To the extent that the full amount of the RTBM Start-Up Offer is not
accounted for in the last RUC make whole payment eligibility period in
the Operating Day, any remaining RTBM Start-Up Offer costs are carried
forward for recovery in the first RUC make whole payment eligibility
period of the following Operating Day provided that the Resource has not
been committed in the Day-Ahead Market in any hour of the first RUC
make whole payment eligibility period as described in (h) below.

(h) If the Resource has been committed in the Day-Ahead Market in a period
adjacent to and following a RUC make whole payment eligibility period to
the extent that the full amount of the RTBM Start-Up Offer is not
accounted for in the RUC make whole payment eligibility period, any
remaining RTBM Start-Up Offer costs are carried forward for recovery in
the Day-Ahead make whole payment eligibility period.

(i) If a Resource has operated outside of its Operating Tolerance in any
Dispatch Interval, any cost associated with energy output above the
Resource’s economic operating point is not eligible for recovery for that
Dispatch Interval where such cost is calculated as described under
Subsection 4(c) below.

(j) If a Resource becomes non-dispatchable in any Dispatch Interval, any cost
associated with energy output above the Resource’s economic operating
point is not eligible for recovery for that Dispatch Interval where such cost
is calculated as described under Subsection 4(c) below.

(k) If a Resource’s minimum operating limit is increased above the
Resource’s minimum operating limit that was used to make the
commitment decision, the increase is greater than the Resource’s
Operating Tolerance and the Resource remains dispatchable in any
Dispatch Interval, any cost associated with energy output above the
Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Subsection 4(c) below.

(l) For combined cycle Resources that are registered consistent in accordance with the offer submission option described under Section 4.1.2.2(4) of this Attachment AE, additional costs associated when with situations in which the Resource has cleared Operating Reserve in the Day-Ahead Market and must buy back that position in Real-Time at an average hourly Real-Time MCP that is greater than the Day-Ahead MCP, the Market Participant may be eligible for a make-whole payment. To be eligible, these costs must be incurred during time periods in which the Resource is transitioning between configurations, at the direction of the Transmission Provider, and such cost is not due to any independent action of the Market Participant. In such cases, the additional costs are equal to the difference between the average hourly Real-Time MCP and the Day-Ahead MCP multiplied by the Day-Ahead Market cleared Operating Reserve MW amounts. For Contingency Reserve, recovery of these costs is limited to the time period defined as the Transition State Time submitted in the Resource Offer. For Regulation-Up and/or Regulation-Down, recovery of these costs is limited to the hours in which the Resource is transitioning between from one configuration to another.

(4) The payment to each Asset Owner for each eligible Settlement Location for a given RUC make whole payment eligibility period is calculated as follows:

RUC Make Whole Payment Amount =

Maximum of [Either Zero or (RUC Make Whole Payment Cost Amount in the RUC Make Whole Payment Eligibility Period + RUC Make Whole Payment Revenue Amount in the RUC Make Whole Payment Eligibility Period – Uninstructed Resource Deviation Cost Disallowance – Non-Dispatchable Cost Disallowance – Minimum Limit Cost Disallowance)]
(a) An Asset Owner’s RUC Make Whole Payment Cost Amount for each eligible Resource is equal to the sum for all Dispatch Intervals in the RUC Make Whole Payment Eligibility Period of:

(i) Start-Up Offer used to make the commitment decision;

(ii) No-Load Offers used to the make the commitment decision, except when a that, for combined cycle Resources cleared in the Day-Ahead Market that were transitioned by the Transmission Provider into a different configuration in Real-Time, in which case the positive difference between the hourly RTBM No-Load Offers used to make the combined cycle Resource transition decision and the hourly Day-Ahead Market No-Load Offers used to make the commitment decision is utilized;

(iv) The Transition State Offer used to make the transition decision for combined cycle Resources cleared in the Day-Ahead Market that were transitioned by the Transmission Provider into a different configuration in Real-Time, the Transition State Offer used to make the transition decision;

(iii) Energy cost at minimum output as calculated from the Energy Offer Curve used to make the commitment decision except that, for when a combined cycle Resources is cleared in the Day-Ahead Market that were transitioned into a different configuration in Real-Time, in which case the value cost shall only be calculated based on the positive difference between calculated for the portion of the Resource’s Real-Time Balancing Market applicable minimum limit and that exceeds the Resource’s Day-Ahead Market cleared quantity, where the Resource’s Real-Time Balancing Market applicable minimum limit is equal to the lesser of the minimum limits submitted as part of the Real-Time Balancing Market Resource Offer or the Resource’s actual output;

(iv) Energy cost above minimum output as calculated from the Energy Offer Curve that applied to the current Dispatch Interval except
that, when a combined cycle Resource is cleared in the Day-Ahead Market that was transitioned into a different configuration in Real-Time, in which case the value cost shall only be calculated based on the positive difference between the portion of the actual Resource output that exceeds and the Resource’s Day-Ahead Market cleared Energy quantity:

and (vii) for Resources other than combined cycle Resources cleared in the Day-Ahead Market that were transitioned into a different configuration in Real-Time, Operating Reserve cost associated with cleared Real-Time Operating Reserve as calculated from the Operating Reserve Offers except that Operating Reserve costs associated with self-scheduled Operating Reserve where such self-schedules are less than or equal to the amount of Operating Reserve cleared shall be set equal to zero;

(viii) for combined cycle Resources cleared in the Day-Ahead Market that were transitioned into a different configuration in Real-Time, the Operating Reserve cost associated with cleared Real-Time Operating Reserve in excess of cleared Day-Ahead Market Operating Reserve as calculated from the Real-Time Operating Reserve Offers except when self-scheduled Operating Reserve is less than or equal to the amount of Real Time Operating Reserve cleared then the Real-Time Operating Reserve costs associated with self-scheduled Operating Reserve where such self-schedules are less than or equal to the amount of Real-Time Operating Reserve cleared shall be set equal to zero; and

(ix) for combined cycle Resources cleared in the Day-Ahead Market that were transitioned into a different configuration in Real-Time and are transitioning into that configuration, the Operating Reserve cost associated with cleared Day-Ahead Market Operating Reserve shall be equal to the maximum of (1) zero or (2) the difference between the applicable Real-Time MCP and the applicable Day-
Ahead MCP multiplied by the cleared Day-Ahead Market Operating Reserve.

(b) An Asset Owner’s RUC Make Whole Payment Revenue Amount for each eligible Resource is equal to the sum for all Dispatch Intervals in the RUC Make Whole Payment Eligibility Period of:

(i) Dispatch Interval revenue associated with Energy calculated by multiplying actual Dispatch Interval Energy output, in MW, by Real-Time LMP, except that for combined cycle Resources cleared in the Day-Ahead Market that were transitioned into a different configuration in Real-Time, Dispatch Interval revenue associated with Energy is equal to Real-Time LMP multiplied by one-twelfth of the positive difference between actual Dispatch Interval Energy output, in MW, and Energy cleared on that Resource in the Day-Ahead Market;

(ii) the sum of the revenues calculated under Section 8.6.2, 8.6.3 and 8.6.4 of this Attachment AE for that eligible Resource;

(iii) Energy revenue associated with payments made under Section 8.6.6 of this Attachment AE; and

(iv) amounts associated with settlement made under Section 8.6.15 of this Attachment AE.

(c) An Asset Owner’s Uninstructed Resource Deviation Cost Disallowance, Non-Dispatchable Cost Disallowance, or Minimum Limit Cost Disallowance is equal to the positive difference between the Resource’s Energy cost at actual output as calculated from the Resource’s current Dispatch Interval Energy Offer Curve and the Resource’s Energy cost at the Resource’s economic operating point as calculated from the Resource’s current Dispatch Interval Energy Offer Curve.

(d) A Resource’s economic operating point is the MW output where the cost on the Resource’s current Dispatch Interval Energy Offer Curve is equal to the Real-Time LMP for that Resource.

8.6.7 Reliability Unit Commitment Make Whole Payment Distribution Amount
An RTBM system-wide and local charge will be calculated at each Settlement Location for each Asset Owner for each hour in order to fund the payments made under Section 8.6.5. The system-wide amount will be determined by multiplying an Asset Owner’s system-wide distribution volume by a daily system-wide RUC make whole payment rate as described in Section 8.6.7(A) of this Attachment AE. The local amount will be determined for each Settlement Area impacted by a Local Reliability Issue will be determined by multiplying an Asset Owner’s local Settlement Area distribution volume by a daily local Settlement Area RUC make whole payment rate as described in Section 8.6.7(B) of this Attachment AE.

A. The RUC System-Wide Make Whole Payment Distribution Amount shall be calculated as follows:

The RUC System-Wide Make Whole Payment Distribution Amount =

\[(\text{RUC System-Wide Make Whole Payment Distribution Rate}) \times (\text{RUC System-Wide Make Whole Payment Distribution Volume})\]

(1) The RUC System-Wide Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day as calculated under Section 8.6.5 excluding make whole payments made to Resources committed by the Transmission Provider at the request of a local transmission operator or committed by a local transmission operator to address a Local Reliability Issue, divided by the sum of Asset Owners’ RUC System-Wide Make Whole Payment Distribution Volumes for all Settlement Locations for the entire Operating Day.

(2) An Asset Owner’s RUC System-Wide Make Whole Payment Distribution Volume at a Settlement Location for an hour is equal to the sum of following values that are calculated for each Dispatch Interval within the hour:

(a) The absolute value of the sum of actual Real-Time Settlement Location deviations from Day-Ahead Market cleared amounts for load, virtual transactions and interchange transactions except that, during any Dispatch Interval in which the Transmission Provider has declared an Emergency Condition due to a capacity shortage, Real-Time actual load deviations from Day-Ahead Market cleared amounts shall be limited to deviations
associated with actual Real-Time load in excess of amounts cleared in the Day-Ahead Market;

(b) For Resources cleared in the Day-Ahead Market, other than combined cycle Resources that have registered under the option described under Section 4.1.2.2(4) of this Attachment AE that have been transitioned in Real-Time by the Transmission Provider into a configuration with higher minimum limits, the positive difference between RTBM Resource applicable minimum limits and Day-Ahead Market Resource minimum limits, if:

(i) Such difference is greater than the Resource’s Operating Tolerance; and

(ii) The applicable RTBM Resource minimum limit is greater than the Day-Ahead Market cleared Energy amount; and

(iii) The Resource received a Dispatch Instruction equal to the RTBM applicable minimum limit for at least one Dispatch Interval in the hour.

(c) For Resources cleared in the Day-Ahead Market, the positive difference between the Day-Ahead Market Resource applicable maximum limits and the RTBM Resource applicable maximum limits, if:

(i) Such difference is greater than the Resource’s Operating Tolerance; and

(ii) The applicable RTBM Resource maximum limit is less than the Day-Ahead Market cleared Energy amount; and

(iii) The Resource received a Dispatch Instruction greater than or equal to the RTBM applicable maximum limit for at least one Dispatch Interval in the hour.

(d) For Resources cleared in the Day-Ahead Market, the Resource’s Day-Ahead Market cleared amount if that Resource is off-line in the RTBM and if the Resource has not been de-committed by the Transmission Provider;
(e) For Resources that cleared in the Day-Ahead Market that are not able to follow Dispatch Instructions, the absolute value of the difference between a Resource’s actual output and the Resource’s economic operating point. The Resource’s economic operating point is calculated as described under Section 8.6.5(4)(d);

(f) For Resources that were not cleared in the Day-Ahead Market and that self-committed following the close of the Day-Ahead Market, including combined cycle Resources that have registered under the option described under Section 4.1.2.2(4) of this Attachment AE that have self-committed into a configuration with higher minimum limits, the actual Resource output if the Resource received a Dispatch Instruction equal to the applicable RTBM applicable minimum limit for at least one Dispatch Interval in the hour;

(g) A Resource’s economic operating point, as calculated as described under Section 8.6.5(4)(d), for Resources that were committed following the close of the Day-Ahead Market if that Resource is off-line in the RTBM and that Resource was not de-committed by the Transmission Provider; and

(h) The absolute value of a Resource’s URD if that Resource operated outside of its Operating Tolerance and the Resource has not been exempted from URD as described under Section 6.4.1.1 of this Attachment AE.

B. RUC Local Settlement Area Make Whole Payment Distribution Amount shall be calculated as follows:

\[
\text{RUC Local Settlement Area Make Whole Payment Distribution Amount} = ((\text{RUC Local Settlement Area Make Whole Payment Distribution Rate}) \times (\text{RUC Local Settlement Area Make Whole Payment Distribution Volume}))
\]

(1) The RUC Local Settlement Area Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day as calculated under Sections 8.6.5 and 8.6.6 of this Attachment AE for Resources committed within a Settlement Area by the Transmission Provider at the request of a local transmission operator or by a local transmission operator to address a Local Reliability Issue in the
Settlement Area, divided by the sum of Asset Owners’ RUC Local Settlement Area Make Whole Payment Distribution Volumes within the impacted Settlement Area for the entire Operating Day.

(2) An Asset Owner’s RUC Local Settlement Area Make Whole Payment Distribution Volume for the impacted Settlement Area for an hour is equal to that Asset Owner’s Reported Load in that Settlement Area for that hour.

ATTACHMENT AF

3.5 Mitigation Measures for Transition State Offers

MPRR140 has the new version of Mitigation Measures for Transition State Offers section.

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<th>Proposed Criteria Language Revision</th>
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## PRR Impact Analysis Report

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### Impact Analysis Date
- 7/31/2013

### Estimated Cost Impact
- $7,100,000 (plus on-going annual maintenance of $265,000)
- Cost impacts include estimated vendor and SPP costs, and are a Rough Order of Magnitude (ROM) estimate equal to +/- 50%. Vendor costs were estimated by SPP staff.

If approved, this project will be included in the Integrated Marketplace Phase 2 program, and overall program costs will be allocated to this project. The cost listed above does not include these program costs.

### Estimated Project Time Requirements
- TBD
  - Request has been submitted to vendor and we are awaiting response.
  - Current staff estimate is 18 months.

### SPP Applications Impacted

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Check off the systems that are (or may be) impacted.

Include a short explanation as to why each application is (or might be) affected in this area.

**MOS DB (MDB):** Changes will be needed to the MDB in the areas listed below to accommodate the addition of four new resource offer parameters and the management of the business rules associated with those new parameters.
- Additions to MDB Core Data Modeling to incorporate the new parameters.
- Updates and additions to the Current Operation Plan (COP) to capture
transition information for settlement.
- Additions to commitment/regulation management and validation to incorporate new business rules around transition state and availability to provide regulation, etc.
- Updates to MDB integration with other systems (i.e. outages, CRD) regarding the new data fields and values.
- Updates to the CSV file export functionality and the solution data in MDB to incorporate the new parameters and values.

**MCE Modeling:** Changes will be needed to the Market Clearing Engine (MCE) model to accommodate clearing and dispatch of combined cycle units as described in the enhanced combined cycle design. Key changes include substantial updates to the core MCE code, the data model, and the MCE formulation documentation to include the new clearing rules regarding combined cycle configuration based modeling and transition data.

**MOS MUI:** The Market User Interface which includes the web user interface and the API will need to be updated to include the structure for combined cycle configuration based modeling and the new data fields for transition information. Validation changes and new validations will also be needed for the new MUI functionality and for the interfaces with other systems.

**MOS MOI:** The Market Operations Interface (MOI) displays will need to be updated to accommodate display and edit of the new Market data (configuration and transition) associated with the combined cycle design.

**Alstom Settlements System:** Changes to accommodate the addition of the RtTransition5minAmt charge type and associated billing determinants, plus adjustments to existing charge types and determinants to incorporate settlement of combined cycle resources in the enhanced design. Corresponding changes to Settlement statements and reports will also have to be made.

**Centralized Modeling Tool (CMT):** Changes will be needed to the CMT to incorporate the addition of resource configuration based registration data associated with the enhanced combined cycle design, and the management of the business rules associated with the new configuration based modeling data. Key changes include updates to the core model structure, validation changes, and changes to the CMT to MDB interface.
## SPP Long-Term Staffing Impacts

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Additional staff required: Yes [No]

Detail each group separately:

### Members Software Systems/Processes Impacted

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<th>MUI</th>
<th>XML</th>
<th>OPS1 Reports</th>
<th>RTO_SS</th>
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Check off the software systems that are (or may be) impacted.

Include a short explanation as to why each application is (or might be) affected in this area.

**Member Processes Impacted:**

**ICCP** – Members will be required to submit new transition state data via ICCP for their Combined Cycle Units.

**MUI** – MUI will contain new fields for capturing resource offer parameters associated with Combined Cycle units (i.e. transition time, transition offer, group min run time, plant min run time). Note: MUI refers to both the Markets User Interface and the API.

**XML** – Additions to XML definitions due to new data fields and new settlements data.

### Evaluation of Interim Solutions (e.g., manual workarounds)

N/A
## Comments

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<thead>
<tr>
<th>SPP agreed to provide this functionality to members by March 1, 2015. Members wanted this functionality included in the market design for the March 1, 2014 implementation. SPP recommended that it be delayed to after go-live since this software code had not been implemented by any other RTO/ISO.</th>
</tr>
</thead>
</table>

This MPRR improves the unit commitment and economic dispatch in the Day-Ahead Market, Reliability Unit Commitment processes and the Real-Time Balancing Market. Members will not have to pre-determine the combined cycle configuration when submitting their Resource Offers. Market operations will benefit from the full combined cycle configurations thus made available to the market.

This MPRR reduces the production cost and improves market operations in the Integrated Marketplace by allowing a more economic commitment and dispatch of the combined cycle Resources. Market Participants will extract more value from the market since these Resources will be more transparently committed and efficiently dispatched. This enhancement was requested by members and approved by the Markets Operations and Policy Committee (MOPC) on April 12, 2011.

A cost benefit analysis was not performed since the SPP resources are focused on Integrated Marketplace. If a cost benefit analysis is required, implementation of the MPRR will need to be delayed to allow time to perform the analysis.
# PRR Recommendation Report

<table>
<thead>
<tr>
<th>PRR No.</th>
<th>Marketplace-PRR131</th>
<th>PRR Title</th>
<th>Settlements Related to PURPA Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>131</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

## Timeline
- [x] Normal  
- [ ] Expedited  
- [ ] Urgent Action

Provide explanation if Expedited and/or Urgent Action is selected:

## Recommendation Action
- [x] Approve  
- [ ] Reject  
- [ ] Require additional information  
- [ ] Defer  
- [ ] Refer

## Impact Analysis Required
- [ ] Yes – If yes, estimated cost:  
- [x] No

SPP Staff will complete this section.

## Protocol Section(s) Requiring Revision
- **Section No.:** 6.1  
- **Title:** Registration of Resources  
- **Protocol Version:** 15.0a

## Type of Revision
- [ ] Correction/Clean-Up  
- [x] Clarification  
- [ ] Design Enhancement  
- [ ] Design Change

## Timeline
- [x] Go-Live  
- [ ] Post Go-Live

## Revision Description
This MPRR clarifies that when a Qualifying Facility that is exercising its PURPA rights is registered in the Integrated Marketplace, that Qualifying Facility will neither be required to participate in the Integrated Marketplace nor be subject to charges or credits related to the Integrated Marketplace.

Currently, the Protocols are not clear if Qualifying Facilities that are exercising their PURPA rights, after they are registered, will be required to participate in the Integrated Marketplace. PRR 243 corrected this in the EIS market, and this MPRR corrects it in the Integrated Marketplace.

## Tariff Implications or Changes
- [x] Yes – Section No: *(Include a summary of impact and/or specific changes)*  
Attachment AE 2.2 Application and Asset Registration
- [ ] No

## Criteria Impact or Changes
- [ ] Yes – Section No: *(Include a summary of impact and/or specific changes)*  
- [x] No

## MWG Review
- **PRR Recommendation**
- **Date of Vote:** 8/6/2013  
- **Vote:** Unanimously Approved  
- **Opposed:** N/A  
- **Abstained:** N/A

## RTWG Review
- **Date of Vote:** 9/5/2013  
- **Vote:** Approved

## ORWG Review
- **Date of Vote:** 8/30/2013  
- **Vote:** Approved with no Reliability Impact

## MOPC Recommendation
- **Date of Vote:**  
- **Vote:**

## Board Review
- **Date of Vote:**  
- **Vote:**
6.1 Registration of Resources

Any Market Participant operating Resources within SPP or representing Asset Owners that are not Market Participants that are operating Resources within SPP must register with SPP via the SPP Market Registration Portal and be capable of performing the functions of a Resource as described herein. Resources are registered on a nodal basis to Settlement Locations. Resources at the same physical and electrically equivalent injection point to the transmission grid may register at the unit or plant level. Failure or refusal to register a Resource will result in SPP filing an unexecuted version of the service agreement as specified in Tariff Attachment AH for that Resource with FERC under the name of the generation interconnection customer under an interconnection agreement with SPP or the applicable TO.

In the case of a Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility, such registration will not require the Qualifying Facility to participate in the Integrated Marketplace or subject the Qualifying Facility to any charges or credits related to the Integrated Marketplace. The Integrated Marketplace charges and payments associated with the Qualifying Facility will be handled in accordance with Attachment AE to the SPP Tariff.

2.2 Application and Asset Registration

(1) Applications for a Market Participant to provide services in the Integrated Marketplace must be submitted to the Transmission Provider prior to the expected date of participation consistent with Section 6.4 of the Market Protocols. Applications must conform to the procedures specified in the Market Protocols and may be rejected if not complete. New Market Participants will follow the timeframe as specified in Section 6.4 of the Market Protocols in addition to the detailed model update timing requirements in Appendix E of the Market Protocols.
(2) As part of the application process, Market Participants must register all Resources and load, including applicable load associated with Grandfathered Agreements (“GFAs”), Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols. As part of Resource registration, Market Participants must specify whether settlement meter data will be submitted on a gross basis or net basis, where gross meter data does not include reductions for auxiliary load and net meter data is gross meter data reduced by auxiliary load. Both Non-Conforming Load and Demand Response Load may only be associated with a single Price Node except that Non-Conforming Load and Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes. Non-participating embedded load and/or generation must either: (i) register its load and/or generation in the Integrated Marketplace; or (ii) transfer its load and/or generation to an external Balancing Authority.

(3) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Data Submittal Locations associated with their load assets. Market Participants may not aggregate multiple Resource Meter Data Submittal Locations into a single Resource Settlement Location unless the Resources are at the same physical and electrically equivalent injection point to the Transmission System.

(4) In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants wishing to model each participant’s share of a Jointly Owned Unit as a separate Resource must choose one of the two options described below and provide the specified additional information. A Resource registered as a combined cycle Resource may not register as a Jointly Owned Unit.

(a) Individual Resource Option

Under the individual Resource option, each participant’s share is modeled as a separate Resource for the purposes of commitment and dispatch and each Resource may be committed independent of the other Resource shares. In order to qualify for this option, each Market Participant must register its share and certify that it is greater than or equal to the minimum physical capacity operating limit of the physical Jointly Owned Unit.

The operating owner’s Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.
Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit;
- Maximum physical ten (10) minute response from an off-line state.

(b) Combined Resource Option

Under the combined Resource option each participant’s share is modeled and must be registered as a separate Resource. Under this option, the commitment decision is made assuming that all Resource shares must be committed or none at all. Once committed, each share is dispatched independently. This option must be selected if the eligibility criteria stated under the individual Resource option cannot be met.

The operating owner’s Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit;
- Maximum physical ten (10) minute response from an off-line state;
- Participant share percentage by Market Participant.

(5) Market Participants may modify their registered assets in accordance with the asset registration procedures specified in the Market Protocols.

(6) All loads and all Resources, excluding Behind-The-Meter Generation less than 10 Megawatts (“MWs”), must register. Failure or refusal to register a Resource will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in the Energy and Operating Reserve Markets or subject the Qualifying Facility to any charges.
or payments related to the Energy and Operating Reserve Markets. Any Energy and Operating Reserve Market charges or payments associated with the output of the Qualifying Facility will be allocated to the Market Participant representing the host utility purchasing the output of the Qualifying Facility under PURPA, and the Market Participant will be provided the settlement data required to verify the settlement charges and payments.

(7) A Market Participant wishing to Offer an External Resource in the Energy and Operating Reserve Markets will utilize an External Resource Pseudo-Tie in accordance with Attachment AO. In addition to the responsibilities outlined in Attachment AO, the Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in the Energy and Operating Reserve Markets.

(8) A Market Participant wishing to offer Demand Response Load as a Demand Response Resource in the Energy and Operating Reserve Markets must include in its application and registration a certification that participation in the Energy and Operating Reserve Markets by its Demand Response Resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Consistent with Section 2.8 of this Attachment, an aggregator of retail customers wishing to offer Demand Response Load in the form of a Demand Response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year. Demand Response Resources must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).
(9) An aggregator of retail customers offering Demand Response Load of one or more end-use retail customers as a Demand Response Resource in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants as well as certification consistent with Section 2.8 of this Attachment.

(10) A wind-powered Variable Energy Resource with (1) an interconnection agreement executed after May 21, 2011 or (2) an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation on or after October 15, 2012 must register as a Dispatchable Variable Energy Resource. A wind-powered Variable Energy Resource with an interconnection agreement executed on or prior to May 21, 2011 may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider. Variable Energy Resources with fuel sources other than wind may optionally register as a Dispatchable Variable Energy Resource. Otherwise, Variable Energy Resources must register as Non-Dispatchable Variable Energy Resources. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

(11) A Market Participant that is selling firm power to the load asset under a bilateral contract may, with the agreement of the buyer, register all or a portion of the buyer’s load as its load asset. For purposes of this Section 2.2(11) of this Attachment AE, the sale of firm power shall refer to power sales deliverable with firm transmission service, where the capacity and energy is supplied under standards of reliability and availability equivalent to supply of native load customers with the supplier assuming the obligation to provide both capacity and energy.

<table>
<thead>
<tr>
<th>Proposed Criteria Language Revision</th>
</tr>
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<tbody>
<tr>
<td>N/A</td>
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### PRR Recommendation Report

<table>
<thead>
<tr>
<th>PRR No.</th>
<th>Marketplace-PRR132</th>
<th>PRR Title</th>
<th>Reserve Sharing Group Registration and Settlements</th>
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</thead>
<tbody>
<tr>
<td></td>
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<td></td>
<td>Normal</td>
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</tbody>
</table>

#### Timeline

- **Provide explanation if Expedited and/or Urgent Action is selected:**
  
  This clarification is needed for completion of registration by RSG members so that the RSG process can be tested as part of Market Trials.

#### Recommendation Action

- **Approve**
- **Reject**
- **Require additional information**
- **Defer**
- **Refer**

#### Impact Analysis Required

- **Yes – If yes, estimated cost:**
- **No**

  **SPP Staff will complete this section.**

#### Protocol Section(s) Requiring Revision

- **Section No.:** Glossary; 4.4.3.5; 4.5.9.22; 6.4; 6.5 (new)
- **Title:** Glossary; Reserve Sharing Group Scheduling Procedures; Real-Time Reserve Sharing Group Amount; Network and Commercial Model Updates; Registration of External Participants in the Reserve Sharing Group (new)
- **Protocol Version:** 15.0a

#### Type of Revision

- **Correction/Clean-Up**
- **Clarification**
- **Design Enhancement**
- **Design Change**

#### Timeline

- **Go-Live**
- **Post Go-Live**

#### Revision Description

With Integrated Marketplace and SPP becoming a Balancing Authority (BA), SPP BA will also become a Member of the Reserve Sharing Group (RSG) that is administered by the SPP RTO. For the SPP BA, the response to RSG events will be handled by the Integrated Marketplace.

SPP BA will also use the Integrated Marketplace Settlements System as the mechanism for financial settlement of RSG activity with other RSG Members. Therefore, the RSG Members external to the Marketplace footprint will need to complete a registration process that captures appropriate data for the Marketplace Settlements System, and which gives the RSG Members access to the Settlements interface of the Marketplace Portal.

This MPRR adds Protocol language to describe the requirements for RSG registration. It also adds and changes Protocol and Tariff language to describe the process that will be used for Settlements of RSG events.

#### Tariff Implications or Changes

- **Yes – Section No:** *(Include a summary of impact and/or specific changes)*

  Attachment AE – 1.1 Definitions; 8.6.17 – Real-Time Reserve Sharing Group Amount; Attachment AK Treatment of Reserve Sharing Charges and Revenues

- **No**
<table>
<thead>
<tr>
<th>Review Type</th>
<th>Date of Vote</th>
<th>Vote</th>
<th>Opposed</th>
<th>Abstained</th>
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<td>7/23/2013</td>
<td>Approved</td>
<td>N/A</td>
<td>Exelon, Xcel</td>
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<tr>
<td>Date of Vote: 9/10/2013</td>
<td>Vote: Approved RTW changes</td>
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<tr>
<td>RTWG Review</td>
<td>8/22/2013</td>
<td>Approved with Modifications</td>
<td></td>
<td></td>
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<tr>
<td>ORWG Review</td>
<td>8/15/2013</td>
<td>Approved with no Reliability Impact</td>
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<td>MOPC Recommendation</td>
<td></td>
<td>Vote:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Board Review</td>
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<td>Vote:</td>
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Date 6/11/2013

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<tr>
<td></td>
<td>Gay Anthony</td>
<td><a href="mailto:ganthony@spp.org">ganthony@spp.org</a></td>
<td>Southwest Power Pool</td>
<td>501-688-1722</td>
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Comments Received

<table>
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<tr>
<th>Comment Author</th>
<th>Date</th>
<th>Comment Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Micha Bailey on behalf of MWG</td>
<td>7/25/2013</td>
<td>The words “each Settlement Location” was taken out of the language in Section 4.5.9.22. The language “the applicable External Interface Settlement Location between the RSG member and SPP” was added in its place for clarity.</td>
</tr>
<tr>
<td>MWG approved the MPRR as modified. The approved language is reflected in this recommendation report.</td>
<td></td>
<td></td>
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<table>
<thead>
<tr>
<th>Comment Author</th>
<th>Date</th>
<th>Comment Description</th>
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<tbody>
<tr>
<td>Brenda Frícano on behalf of the RTWG</td>
<td>8/22/2013</td>
<td>RTWG change “Revenues” to “Energy Charges” in attachment AK section III and deleted the paragraph titled “Revenues for Transmission Service Charges”. The deleted paragraph was moved under section IV in attachment AK. RTWG also made general grammar corrections. <strong>RTWG changes are highlighted in yellow.</strong></td>
</tr>
<tr>
<td>MWG approved the MPRR as modified. The approved language is reflected in this recommendation report.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
1. Glossary

Reserve Sharing Event
A request for assistance to deploy Contingency Reserve by any signatory to the Reserve Sharing Group Agreement any Reserve Sharing Group (RSG) member following the sudden loss of a Resource.

Reserve Sharing Group
As defined in the SPP Tariff.

4.5.9.22 Real-Time Reserve Sharing Group Amount

(1) An RTBM credit or charge for requested assistance provided between Reserve Sharing Group members following a Resource contingency will be calculated for each RSG Asset Owner−counterparty to account for differences between LMP at the External Interface Settlement Location and the contract rate between the applicable RSG member and SPP. Import transactions will include external RSG member transmission charges, as specified in the Reserve Sharing Agreement. Charges and credits for this activity will be represented under the following charge type calculated as follows:

\[
\text{IF } \text{RsgCrdFlg}_t = 1 \\
\text{THEN} \\
\#\text{RtRsg5minAmt}_{a,s,i,t} = \text{RtImpExp5minQty}_{a,s,i,t} \\
* \text{Max} (0, \text{RsgContractPrc}_{a,i,t} - \text{RtLmp5minPrc}_{s,i}) / 12 + \text{RsgTransAmt}_{a,t,i}
\]

(2) For each RSG Asset Owner, an hourly amount is calculated at the applicable External Interface Settlement Location between the RSG member and SPP. The amount is calculated as follows:

\[
\text{RtRsgHrlyAmt}_{a,h,a,s,h} = \sum_i \sum_t (\text{RtRsg5minAmt}_{a,s,i,t})
\]
(3) For each RSG Asset Owner, a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{RtRsgDlyAmt}_{a, d} = \sum_{h} \sum_{s} \text{RtRsgHrlyAmt}_{a, s, h} \]

(4) For each RSG Market Participant, a daily amount is calculated representing the sum of RSG Asset Owner amounts associated with that RSG Market Participant. The daily amount is calculated as follows:

\[ \text{RtRsgMpAmt}_{m, d} = \sum_{a} \text{RtRsgDlyAmt}_{a, d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtRsg5minAmt&lt;sub&gt;a, s, i, t&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Reserve Sharing Group Agreement Amount per RSG Asset Owner per Settlement Location per Dispatch Interval per Reserve Sharing Event Transaction - The RTBM amount to SPP from the RSG counterparty AO for assistance provided by SPP or the RTBM amount from SPP to the RSG counterparty AO for assistance provided by the RSG counterparty for Reserve Sharing Event transaction at interface Settlement Location &lt;i&gt;s&lt;/i&gt; in Dispatch Interval &lt;i&gt;i&lt;/i&gt;. Note use of the Asset Owner subscript for the counterparty does not require that counterparty to become an actual Market Participant or be represented by a Market Participant. This is only required in this case to effectuate an automated billing mechanism.</td>
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<tr>
<td>RsgCrdFlg&lt;sub&gt;t&lt;/sub&gt;</td>
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<td>None</td>
<td>Reserve Sharing Group Contingency Reserve Deployment Flag per Event – The value described under Section 4.5.8.8.</td>
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<td>RtImpExp5minQty&lt;sub&gt;a, s, i, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Interchange Transaction Quantity per RSG AO per Settlement Location per Dispatch Interval per Transaction – The value described under Section 4.5.9.2 associated with RSG schedules.</td>
</tr>
<tr>
<td>RsgContractPrc&lt;sub&gt;a, i, t&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td>Reserve Sharing Group Contract Price per AO per Dispatch Interval per Transaction – The Energy price specified in the RSG Agreement to be applied to RSG Energy Schedules for assistance provided by SPP BA to an External RSG member and assistance provided by an External RSG member to the SPP BA.</td>
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<tr>
<td>RsgTransAmt&lt;sub&gt;a, t, i&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td>Reserve Sharing Group Transmission Charge per AO per Dispatch Interval per Transaction – The transmission charge in the RSG Agreement to be applied to RSG Energy Schedules for assistance provided by an External RSG member to the SPP BA.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------</td>
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<td>---------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
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<tr>
<td>RtRsgHrlyAmt&lt;sub&gt;a, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td><strong>Real-Time Reserve Sharing Group Agreement Amount per Asset Owner per Settlement Location per Hour</strong> - The RTBM amount to SPP from the RSG counterparty AO for assistance provided by SPP or the RTBM amount from SPP to the RSG counterparty AO for assistance provided by the RSG counterparty at interface Settlement Location &lt;sub&gt;s&lt;/sub&gt; in Hour &lt;sub&gt;h&lt;/sub&gt;. Note use of the Asset Owner subscript for the counterparty does not require that counterparty to become an <em>actual</em> Market Participant or be represented by a Market Participant. This is only required in this case to effectuate an automated billing mechanism.</td>
</tr>
<tr>
<td>RtRsgDlyAmt&lt;sub&gt;a, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Reserve Sharing Group Agreement Amount per RSG Asset Owner per Operating Day</strong> - The RTBM amount to SPP from the RSG counterparty AO for assistance provided by SPP or the RTBM amount from SPP to the RSG counterparty AO for assistance provided by the RSG counterparty in Operating Day &lt;sub&gt;d&lt;/sub&gt;. Note use of the Asset Owner subscript for the counterparty does not require that counterparty to become an <em>actual</em> Market Participant. This is only required in this case to effectuate an automated billing mechanism.</td>
</tr>
<tr>
<td>RtRsgDlyAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Reserve Sharing Group Agreement Amount per Asset Owner, RSG Market Participant per Operating Day</strong> - The RTBM amount to SPP from the RSG counterparty AO-MP for assistance provided by SPP or the RTBM amount from SPP to the RSG counterparty AO-MP for assistance provided by the RSG counterparty in Operating Day &lt;sub&gt;d&lt;/sub&gt;. Note use of the Asset Owner, Market Participant subscript for the counterparty does not require that counterparty to become an <em>actual</em> Market Participant or be represented by a Market Participant. This is only required in this case to effectuate an automated billing mechanism.</td>
</tr>
</tbody>
</table>

- <sup>m</sup> none none An RSG Market Participant.
- <sup>a</sup> none none An RSG Asset Owner.
- <sup>h</sup> none none An Hour.
- <sup>i</sup> none none A Dispatch Interval.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>( t )</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Bilateral Settlement Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
</tbody>
</table>
6.3 Registration of Meter Agent
All Meter Agents (MA) providing meter data under SPP Tariff must register with SPP via the SPP Market Registration Portal. To become registered, MA must be able to demonstrate to SPP that it is capable of performing the functions as described herein. Meter data will be provided with the content and format prescribed in these protocols. The Market Participant is also responsible for insuring that SPP also receives Settlement Location Data from the Meter Agent in a suitable electronic format.

6.4 Network and Commercial Model Updates
Exhibit 6-3 shows the Model Update Timeline. Existing Market Participant Registration related model changes take place as outlined in the table below. New Market Participant Registration related model changes take place three times per year as indicated in the table below. Exceptions to this process can be made on a case-by-case basis as determined by SPP. Detailed model update timing relating to registration of new assets and changes to existing asset is included in Appendix E.

6.5 Registration of External Participants in the Reserve Sharing Group
Any external entity participating in the RSG shall complete the Reserve Sharing Group (RSG) registration process through the SPP Customer Relations Department to capture data for SPP’s Integrated Marketplace settlements system, and to establish RSG member access to the Settlements interface of the SPP Marketplace Portal. The Marketplace Settlements system is the mechanism used for financial settlement of RSG activities with SPP as specified in the SPP Tariff.

Proposed Tariff Language Revision

ATTACHMENT AE
INTEGRATED MARKETPLACE

1.1 Definitions R
Reserve Sharing Event
A request for assistance to deploy Contingency Reserve by any signatory member of the Reserve Sharing Group Agreement following the sudden loss of a Resource.

Reserve Sharing Group
A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority’s use in recovering from contingencies within the group.
**Reserve Sharing Group Agreement**

The Agreement detailing the rights and obligations of the Reserve Sharing Group members for use in recovering from contingencies within the group.

8.6.17 **Real-Time Reserve Sharing Group Amount**

A Real-Time Reserve Sharing Group amount for requested assistance provided between Reserve Sharing Group members following a Resource contingency will be calculated for each counterparty for each hour as specified in the *Reservation Sharing Group Agreement* and Market Protocols.

**ATTACHMENT AK**

**TREATMENT OF RESERVE SHARING CHARGES AND REVENUES**

I. **Reserve Sharing Activation**

In order to activate the Reserve Sharing System, a Balancing Authority operator shall notify the Transmission Provider in accordance with Section 6.4.2 of the SPP Criteria.

II. **Charges for Reserve Sharing Services**

Charges for energy assistance supplied to the SPP Balancing Authority from another Reserve Sharing Group (“RSG”) member during a reserve sharing activation will be calculated in accordance with the applicable contracts between members of the RSG and the Transmission Provider shall collect such charges and render payment to the applicable RSG members in accordance with the settlement procedures specified in Attachment AE.

III. **Energy Revenues** for Reserve Sharing Services

Energy charges collected for energy assistance supplied from the SPP Balancing Authority to another RSG member during a reserve sharing activation will be calculated in accordance with the applicable contracts between members of the RSG and the Transmission Provider shall receive payment from the applicable RSG members and distribute such revenues in accordance with the settlement procedures specified in Attachment AE.
IV. Transmission Service Charges for Reserve Sharing Services

There shall be no Transmission Service charges for use of the Transmission System associated with the Transmission Provider’s activation of the Reserve Sharing System by Transmission Provider on behalf of the SPP Balancing Authority Area. There shall be Transmission Service charges for use of the Transmission System associated with the activation of the Reserve Sharing System for an RSG member that is external to the SPP Balancing Authority Area. Such charges shall include (a) the energy supplied to the external RSG member during a reserve sharing activation event multiplied by the applicable hourly non-firm transmission rates, and (b) any other charges applicable to the provision of non-firm Transmission Service as specified in this Tariff.

Proposed Criteria Language Revision

N/A
## PRR Recommendation Report

<table>
<thead>
<tr>
<th>PRR No.</th>
<th>Marketplace-PRR135</th>
<th>PRR Title</th>
<th>Settlements Clean-up and Clarifications</th>
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### Timeline

- ☒ Normal
- ☐ Expedited
- ☐ Urgent Action

Provide explanation if Expedited and/or Urgent Action is selected:

### Recommendation Action

- ☒ Approve
- ☐ Reject
- ☐ Require additional information
- ☐ Defer
- ☐ Refer

### Impact Analysis Required

- ☐ Yes – If yes, estimated cost: $\_\_\_\_\_\_
- ☒ No

SPP Staff will complete this section.

### Protocol Section(s) Requiring Revision

**Section No.:** 4.3.1.2; 4.3.2.2; 4.4.1.2; 4.4.4.1, 4.4.4.1.1; 4.5.8; 4.5.8.5; 4.5.8.19; 4.5.8.22; 4.5.9.1; 4.5.9.8; 4.5.9.9; 4.5.9.25; 4.5.10.1; 4.5.13.5; 4.5.15

**Title:** DA Market Execution; Day-Ahead RUC Execution; Intra-Day RUC Execution; Uninstructed Resource Deviation; URD Exemptions; Day-Ahead Over-Collected Losses Distribution Amount; Day-Ahead Demand Reduction Distribution Amount; Real-Time Asset Energy Amount; RUC Make-Whole-Payment Amount; Real-Time Out-Of-Merit Amount; Real-Time Demand Reduction Distribution Amount; Transmission Congestion Rights Auction Transaction Amount; Final Settlement Statements; Disputes

**Protocol Version:** 15.0a

### Type of Revision

- ☒ Correction/Clean-Up
- ☒ Clarification
- ☐ Design Enhancement
- ☐ Design Change

### Timeline

- ☒ Go-Live
- ☐ Post Go-Live

### Revision Description

a) Added “and/or Regulation Down” and “and/or Regulation Up” to describe the Max and Min Regulation Capacity Operating Limit is in place when the Resource is selected for Regulation-Up or Regulation-Down.

b) For Resources with same AO at a common bus, (combined output)-(combined Setpoint) will be used to calculate URD at the common bus to determine if URD is within tolerance per 4.4.4.1.1(6). These Resources will not universally be treated as a single Resource.

c) Resource will be exempted from URD for normal CR as well as for CR deployment tests.

d) There are some subscripts in Over Collected Losses Distribution Amount section that needs to come out. Deleted an “a” out of DaLpExtSupplyHrlyFct to clarify the calculation.

e) Zonal was already removed from the language in MPRR77. The zonal attribute was not taken out yet.

f) Right now, the protocols state that missing tie values will be 0. State estimator will replace the zeros with values in it when the values are missing. This gives a better solution in Settlements than assuming the missing values are zero.

g) The RUC process uses the start-up cost and energy costs, up to a Resource’s minimum-energy, from their RTBM offer when committing Resources. RTBM uses a Resource’s incremental energy cost and Operating Reserve costs to establish its dispatch and cleared Operating Reserve quantities from the RTBM offer in effect.
when each dispatch interval is being solved. The RTBM MWP calculation is being modified to use the same costs that were used to commit and dispatch the resource.
h) Current language is not clear that a credit may be given for a passed CR test. The added language clarifies that the credit may be given, not only for a Manual Dispatch Instruction, but also for a passed CR Test if the MP incurs a cost.
i) Zonal was already removed from the language in MPRR77. The zonal attribute was not taken out yet.
j) The sign in TcrAucPrc is reversed. This corrects the equation.
k) Added language in response to an RMS ticket to clarify the final Settlement Statement charges are a delta from the initial Settlement Statement.
l) The current Protocols use the words “ad hoc resettlement” to describe the statement type. This MPRR deletes these words and changes the resettlement period from 1-11 to 1-12. This change adds clarity to the Protocols because Settlements only resettles 1-12. There is no “ad hoc” (1.5 or 2.3) statement type.

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<th>✗ Yes – Section No: (Include a summary of impact and/or specific changes)</th>
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<td>Attachment AE Section: 5.1.2 Day-Ahead Market Execution; 5.2.2 Day-Ahead Reliability Unit Commitment Execution; 6.1.2 Intra-Day Reliability Unit Commitment Execution; 6.4.1 Uninstructed Resource Deviation; 6.4.1.1 Uninstructed Resource Deviation Exemptions; 8.6.5 Reliability Unit Commitment Make Whole Payment Amount; Attachment AE Section: 8.6.6 Real-Time Out-of-Merit Amount; 8.7.1 Transmission Congestion Rights Auction Transaction Amount; 10.3 Invoice Disputes</td>
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<td>Board Review Date of Vote: Vote:</td>
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| Date | 7/5/2013 |
| Sponsor | |
| Name | John Luallen |
4.3.1.2 DA Market Execution

SPP clears the Day-Ahead Market for each hour of the upcoming Operating Day based on the inputs described above. A simultaneous co-optimization methodology, utilizing the SCUC and SCED algorithms is employed to simultaneously perform the following tasks:

(1) Commit offered Resources, Import Interchange Transaction Offers and Virtual Energy Offers using the SCUC algorithm to meet the Demand Bids, Virtual Energy Bids, Export Interchange Transactions Bids and Operating Reserve requirements at least cost throughout the projected upcoming Operating Day while respecting Resource operating constraints and transmission constraints;

(a) The DA Market SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market and Self, including Resources committed in the Multi-Day Reliability Assessment process, only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up and/or Regulation-Down) and down to the Resources Minimum Economic Capacity...
Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down and/or Regulation-Up).

(i) If this capacity is not sufficient to meet the fixed Demand Bids and fixed Export Interchange Transaction Bids plus Operating Reserve requirements on a system-wide basis, the DA Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limit and/or commit Resources’ with a Commit Status of Reliability on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

(ii) If there is a capacity surplus on a system-wide basis calculated as the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transaction Offers and the Regulation-Down requirement that is in excess of the sum of Fixed Demand Bids and fixed Export Interchange Transaction Bids, the DA Market SCUC algorithm will, in priority order (1) curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limit on an economic basis until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement to the extent possible.

(b) To the extent that a particular reliability issue cannot be directly addressed within the DA Market SCUC algorithm as described under subsection (i) and (ii) above, SPP may manually commit Resources to alleviate such reliability issues. SPP will re-run the DA Market SCUC algorithm after such manual commitments, time permitting, and will notify the Market Participants that units were manually committed. The SCED algorithm will be run based on the manual commitment to produce a final market solution.

(2) Using the commitment results from the SCUC, clear Resource Offers and Import Interchange Transaction Offers to meet Demand Bids, Virtual Energy Bids, Export Interchange Transaction Bids and Operating Reserve requirements at minimum cost for each hour of the upcoming Operating Day using the SCED algorithm while respecting Resource operating constraints and transmission constraints.
(a) The SCED algorithm includes marginal loss sensitivity factors which approximate the change in marginal system losses for a change in Energy dispatch. Inclusion of these factors further optimizes the Energy dispatch and reduces overall production costs.

(b) In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, SPP must apply Violation Relaxation Limits (VRLs) in SCED as described under Section 4.1.4.

(c) To ensure rational pricing of cleared Operating Reserve products, the SCED algorithm will include product substitution logic as follows:

(i) Any Regulation-Up Offers remaining once the Regulation-Up Requirement is satisfied may be used to meet Contingency Reserve requirements if Regulation-Up Offer is more economic or is required to meet the overall Operating Reserve requirement;

(ii) Any Spinning Reserve Offers remaining once the Spinning Reserve Requirement is satisfied may be used to meet Supplemental Reserve requirements if Spinning Reserve Offer is more economic or is required to meet the overall Operating Reserve requirement;

(iii) The product substitution logic ensures that the MCP for Regulation-Up is always greater than or equal to the Spinning Reserve MCP and that the Spinning Reserve MCP is always greater than or equal to the Supplemental Reserve MCP.

(d) To ensure that Market Participants are indifferent as to whether they are cleared for Energy or Operating Reserve, the co-optimization logic will provide through the Shadow Price calculation Market Clearing Prices for Operating Reserve that include any lost opportunity costs incurred as a result of Operating Reserve clearing.

4.3.2.2 Day-Ahead RUC Execution

Using the inputs described above, SPP performs a capacity adequacy analysis for the upcoming Operating Day using the SCUC algorithm. The capacity adequacy analysis provides advisory information to the SPP Operators.
(1) The objective of the SCUC is to commit Resources to meet the SPP Mid-Term Load Forecast and Operating Reserve requirements over the Operating Day such that commitment costs are minimized while adhering to transmission system security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers;

(2) Commitment costs are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined in the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the RUC SCUC in making commitment decisions;

(3) The SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market or Self only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up and/or Regulation-Down [G3]) and down to the Resources Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down and/or Regulation-Up [G4]).

   (a) If this capacity is not sufficient to meet the system-wide SPP Mid-Term Load Forecast plus Operating Reserve requirements, the SCUC algorithm study will, in priority order: (1) curtail non-firm Export Interchange Transactions until the capacity shortage is eliminated; (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limit and/or commit Resources’ with a Commit Status of Reliability on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

   (b) If the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transaction Offers and the system-wide Regulation-Down requirement is in excess of the sum of the SPP system-wide Mid-Term Load Forecast and fixed Export Interchange Transactions, the RUC SCUC algorithm study will, in priority order: (1) curtail non-firm fixed Import Interchange Transactions until the capacity surplus is eliminated; (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limit on an economic basis until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement to the extent possible; (3) de-commit Resources that were committed in the DA Market with a Commit Status of
Market until the capacity surplus is eliminated; and (4) de-commit Self-Commited Resources until the capacity surplus is eliminated.

(i) If there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, SCUC may commit additional Resources and/or de-commit Resources to relieve the constraints provided that any commitment changes do not aggravate the excess capacity situation.

(c) To the extent that a particular reliability issue cannot be directly addressed within the SCUC algorithm as described under subsection (a) and (b) above, SPP may manually commit Resources with a Commit Status of Reliability, and de-commit Resources with a Commit Status of Self, to alleviate such reliability issues in accordance with its authority as Reliability Coordinator.

(i) An emergency condition may arise within the operating area of a local transmission operator that may involve elements not monitored by SPP. Such emergencies may require out of merit commitment, decommitment or dispatch instructions to be issued to one or more Resources to resolve the emergency. In such cases, the local transmission operator shall request SPP to issue such instructions. To the extent that SPP commits a Resource to address a Local Reliability Issue at the request of a local transmission operator such Resource shall be eligible for compensation in the same manner as any other Resource. Recovery of such compensation shall be collected locally as described under Section 4.5.9.10. If the SPP determines that the instructions were required for regional reliability, recovery of such compensation shall be collected regionally as described under Section 4.5.9.10.

Any curtailment of schedules, use of Reliability Status Resources or use of Emergency operating limits by the RUC algorithms will only be advisory information to the SPP RUC Operators. Day-Ahead RUC and Intra-Day RUC Operators will determine which of these options should be acted on and when as described in the Day-Ahead and Intra-Day RUC Results sections.
4.4.1.2 Intra-Day RUC Execution

Using the inputs described above, SPP performs a capacity adequacy analysis for the upcoming Operating Day and throughout the Operating Day using a SCUC algorithm. The capacity adequacy analysis provides advisory information to the SPP Operators.

1. The objective of the SCUC is to commit Resources to meet the SPP Mid-Term Load Forecast and Operating Reserve requirements over the Operating Day such that commitment costs are minimized while adhering to transmission system security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers;

2. Commitment costs are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined on the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the RUC SCUC in making commitment decisions;

3. The SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market or Self only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up and/or Regulation-Down) and down to the Resources Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down and/or Regulation-Up).

   a. If this capacity is not sufficient to meet the system-wide SPP Mid-Term Load Forecast plus Operating Reserve requirements, the SCUC algorithm study will, in priority order: (1) curtail non-firm Export Interchange Transactions until the capacity shortage is eliminated; (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limit and/or commit Resources’ with a Commit Status of Reliability on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

   b. If the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transaction Offers and the system-wide Regulation-Down requirement is in excess of the sum of the SPP system-wide Mid-Term Load Forecast and fixed Export Interchange Transactions, the SCUC algorithm study will, in priority order: (1) curtail non-firm fixed Import Interchange Transactions until the capacity surplus is eliminated; (2) incorporate capacity down to
Resources’ Minimum Emergency Capacity Operating Limit on an economic basis until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement to the extent possible; (3) de-commit Resources that were committed in the DA Market with a Commit Status of Market until the capacity surplus is eliminated; and (4) de-commit Self-Committed Resources that were committed following the Day-Ahead RUC process until the capacity surplus is eliminated.

(i) If there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, RUC may commit additional Resources to relieve the constraints provided that the additional commitment does not aggravate the excess capacity situation.

(c) To the extent that a particular reliability issue cannot be directly addressed within the SCUC algorithm as described under subsection (a) and (b) above, SPP may manually commit Resources, including Resources with a Commit Status of Reliability, and de-commit Resources, including Resources with a Commit Status of Self, to alleviate such reliability issues in accordance with its authority as Reliability Coordinator.

(d) An emergency condition may arise within the operating area of a local Transmission Operator that may involve elements not monitored by SPP. Such emergencies may require out of merit commitment, decommitment or dispatch instructions to be issued to one or more Resources to resolve the Local Reliability Issue. Time permitting, the local Transmission Operator shall request SPP to issue such instructions. To the extent time does not permit, the local Transmission Operator may issue such instructions to the Resource in accordance with its authorities as a reliability entity. In such cases, the following shall take place:

(i) If initial instructions are issued by a local Transmission Operator, the Transmission Operator shall notify SPP of the instructions given to the Resource.

(ii) The Transmission Operator and SPP will coordinate to ensure subsequent instructions are provided by SPP.
(iii) SPP shall log such instructions as manual commitment, decommitment or Out-of-Merit Dispatch instruction, as appropriate, as if it gave such instruction to the Resource.

(iv) The Resource shall be eligible to receive the compensation for such instructions whether issued by SPP or the local Transmission Operator in the same manner as if it had been committed by SPP, provided that SPP determines that the Resource was selected in a non-discriminatory manner. For purposes of making such determination, the standards and procedures applicable to Resource selection in the Intra-Day Reliability Unit Commitment process as described in Section 6.1.2.1 of Attachment AE to the Tariff, shall apply. Recovery of such compensation shall be collected locally as described under Section 4.5.9.10.

(v) In the event of a Transmission Operator directive, the Transmission Operator and SPP shall collaborate to provide a report with an after-the-fact analysis of the event. All such reports shall be made available to the appropriate stakeholder groups for review on a quarterly basis in the month following the end of the quarter in which the event occurred and will be used to determine the best practice for addressing this type of emergency situation in the future.

(c) In the event that the local transmission operator commits a Resource to resolve an issue other than a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by SPP, provided that SPP determines that the selected Resource was selected in a non-discriminatory manner. For purposes of making such determination, the standards and procedures described in Section 6.1.2.1 of Attachment AE to the Tariff shall apply. Recovery of such compensation shall be collected regionally as described under Section 4.5.9.10.

(f) In the event that SPP commits a Resource at the request of a local transmission operator to resolve an issue other than a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by SPP. Recovery of such compensation shall be collected regionally as described under Section 4.5.9.10.

(g) In the event that SPP commits a Resource at the request of a local transmission operator to resolve a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by SPP. Recovery of such
compensation shall be collected locally as described under Section 4.5.9.10

4.4.1 Uninstructed Resource Deviation

The following rules apply to the calculation of Uninstructed Resource Deviation (URD).

1. URD is the difference between a Resource’s actual average MW output over the Dispatch Interval and the Resource’s average ramped MW Setpoint Instruction over a Dispatch Interval. For the purposes of determining URD exemptions for Resources that are part of a Common Bus as described under Section 4.4.4.1.1(6), each Asset Owner's Resources of a single Asset Owner with Resources at a Common Bus will be aggregated and treated as a single Resource. In such case, the Resources’ combined average ramped MW Setpoint Instruction and the Resources’ combined actual average MW output at the Common Bus will be used for calculation purposes at the Common Bus for the Dispatch Interval for each Asset Owner.

2. A Resource’s URD is allocated a portion of the RUC Make-Whole Payment costs in any Dispatch Interval where Resource’s URD is outside of its Operating Tolerance unless that Resource has been exempted from URD under Section 4.4.4.1.1.

   a. A generating unit Resource’s Operating Tolerance in each Dispatch Interval is equal to the Resource’s Maximum Emergency Capacity Operating Limit multiplied by 5%, subject to a minimum of 5 MW and a maximum of 20 MW.

   b. A Dispatchable Demand Response Resource’s Operating Tolerance in each Dispatch Interval is equal to the resource’s Maximum Emergency Capacity Operating Limit multiplied by 5%, subject to a minimum of 5 MW and a maximum of 20 MW.

   c. A Block Demand Response Resource’s Operating Tolerance in each Dispatch Interval is equal to the resource’s Maximum Economic Capacity Operating Limit multiplied by 5%, subject to a minimum of 5 MW and a maximum of 20 MW.

   d. The Common Bus Operating Tolerance for each Asset Owner registered at a Common Bus is equal to the sum of that Asset Owner’s Resources’ Maximum Emergency Capacity Operating Limits for Resources that are on-line multiplied by 5%, subject to a minimum of 5 MW and a maximum of 20 MW.
(e) If the absolute value of a Resource’s URD is greater than the Resource’s Operating Tolerance in any Dispatch Interval, the Resource URD / 12 is included in the hourly allocation of RUC Make-Whole Payment cost allocation. The hourly URD amount is calculated as the sum of Dispatch Interval URD for the hour. See Section 4.5.9.10 for calculation details. Additionally, if that Resource was eligible to receive a RUC Make-Whole Payment, the payment may be reduced. See Section 4.5.9.8 for calculation details.

4.4.4.1.1 URD Exemptions

A Resource’s URD will receive a URD exemption in a Dispatch Interval shall be considered equal to zero (0) under the following situations:

1. The Resource is deployed for Contingency Reserve as described under Section 4.4.3.4 or is deployed for a Contingency Reserve test as described under Sections 6.1.11.1 and 6.1.11.2;

2. The Resource trips or is derated after receiving Dispatch Instructions;

3. There is missing or bad Resource SCADA data in the Dispatch Interval;

4. During a system Emergency if the URD is associated with actual Resource output above the Resource’s Setpoint Instruction in a shortage condition or if the URD is associated with actual Resource output below the Resource’s Setpoint Instruction during an excess generation condition;

5. If a Dispatch Instruction is issued to a Resource beyond the reported capabilities due to the application of a VRL;

6. If the Resource is part of a Common Bus and the URD calculated at the Common Bus is less than the Operating Tolerance calculated at the Common Bus;

7. A Resource SPP may set will receive an Uninstructed Resource Deviation exemption to zero (0) to the extent a Market Participant can demonstrate the URD resulted from an event of Force Majeure or, in the case of a Variable Energy Resource, if the URD results from extremely high wind or other extreme weather-related conditions materially and directly impacting a Variable Energy Resource’s ability to provide Energy. An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or any order, regulation or restriction imposed by governmental military or lawfully established civilian authorities. A Force Majeure event
does not include an act of negligence or intentional wrongdoing such deviation was caused solely by events or conditions beyond its control, and without the fault or negligence of the Market Participant. The Market Participant must provide SPP with adequate documentation through the dispute process in order for the Market Participant to be eligible to avoid such Uninstructed Resource Deviation. SPP shall determine through the dispute process whether such Uninstructed Resource Deviation should be waived.

(8) The Resource is issued an OOME instruction.

In the event a Resource does not receive a URD exemption in a Dispatch Interval, the Market Participant may provide SPP with adequate documentation through the dispute process in order for the Market Participant to be eligible to avoid such Uninstructed Resource Deviation. SPP shall determine through the dispute process whether an exemption will be given. Adequate documentation may include but is not limited to an audio file documenting a call between the Market Participant and SPP.

4.5.8.19 Day-Ahead Over-Collected Losses Distribution Amount

(1) The Marginal Losses Component of the DA Market LMP that results from the economic market solution which considers the cost of marginal losses, congestion costs and incremental Energy costs creates an over collection related to payment for losses (“DA Market Over-Collected Losses”) that must be refunded. A DA Market credit or charge is calculated for each hour at each Settlement Location for which an Asset Owner has a DA Market Energy withdrawal that contributed positively to the over collection. Each Asset Owner’s contribution to the DA Market Over-Collected Losses is calculated based upon a Loss Pool that is dynamically defined by the Asset Owner’s transactional activity. A loss rebate factor is calculated for each Asset Owner and withdrawal Settlement Location as the difference between the Marginal Loss Component at a withdrawal Settlement Location in the Asset Owner’s Loss Pool and the injection weighted average Marginal Loss Component for the Asset Owner’s Loss Pool, multiplied by the Asset Owner’s share of the net withdrawal (calculated excluding cleared Virtual Bids and cleared Virtual Offers) at that Settlement Location. The injection weighted average MLC for the Asset Owner’s Loss Pool is calculated assuming that injection in the Loss Pool first serves withdrawal in the Loss Pool and then goes to meet the withdrawal in Loss Pools which do not have sufficient injections to

1 Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
meet all withdrawals. The loss rebate factor (positive value only, negative values are ignored) is a measure of the Asset Owner’s payment for losses on a marginal basis at each Settlement Location. The loss rebate factors are then normalized to allocate a pro-rata portion of the total over collection in the hour to Asset Owners by Settlement Location. The amount is calculated as follows:

\[
\#\text{DaOclDistHrlyAmt}_{a,s,lp,h} = \text{DaNormLossRbtHrlyFct}_{a,s,lp,h} \times \text{DaOclHrlyAmt}_h \times (-1)
\]

Where,

(a) \[
\text{DaOclHrlyAmt}_h = \sum_a \sum_s \sum_{lp} (\text{DaLmpHrlyPrc}_{s,h} - \text{DaMccHrlyPrc}_{s,h}) \times (\text{DaClrdHrlyQty}_{a,s,lp,h} + \sum_i \text{DaClrdVHrlyQty}_{a,s,lp,h,i,t} + \sum_i \sum_t \text{DaImpExp5minQty}_{a,s,lp,i,t} / 12)
\]

(b) IF \text{DaLossRbtSppHrlyFct}_h = 0

THEN

\text{DaNormLossRbtHrlyFct}_{a,s,lp,h} = 0

ELSE

\[
\#\text{DaNormLossRbtHrlyFct}_{a,s,lp,h} = \text{Max} \left( 0, \text{DaLossRbtHrlyFct}_{a,s,lp,h} \right) / \text{DaLossRbtSppHrlyFct}_h
\]

(b.1) \[
\text{DaLossRbtSppHrlyFct}_h = \sum_a \sum_s \sum_{lp} \text{Max} \left( 0, \text{DaLossRbtHrlyFct}_{a,s,lp,h} \right)
\]

(c) \[
\#\text{DaLossRbtHrlyFct}_{a,s,lp,h} = \left| \text{DaLpIntSupplyHrlyFct}_{lp,h} \right| \times (\text{DaMlcHrlyPrc}_{s,h} - \text{DaLpIwaMlcHrlyPrc}_{lp,h}) + (1 - \text{DaLpIntSupplyHrlyFct}_{lp,h})
\]
\[
\begin{align*}
* \ ( \text{DaMlcHrlyPrc}_{s, h} - \text{DaSppIwaMlcHrlyPrc}_{h} ) \]

* \ \text{DaLpNetWdrHrlyQty}_{a, s, lp, h}

(c.1) \text{IF} \ \text{DaAoNetWdrSppHrlyQty}_{s, h} = 0 \\
\text{THEN} \\
\text{DaLpNetWdrHrlyQty}_{a, s, lp, h} = 0 \\
\text{ELSE} \\
\text{DaLpNetWdrHrlyQty}_{a, s, lp, h} = \text{DaSlNetWdrHrlyQty}_{s, h} \\
\text{ELSE} \\
\text{DaAoNetWdrHrlyQty}_{a, s, lp, h} = \{ \text{DaAoNetWdrHrlyQty}_{a, s, lp, h} / \text{DaAoNetWdrSppHrlyQty}_{s, h} \}

(c.2) \ \text{DaAoNetWdrSppHrlyQty}_{s, h} = \sum_{a} \sum_{lp} \text{DaAoNetWdrHrlyQty}_{a, s, lp, h}

(c.3) \ \text{DaAoNetWdrHrlyQty}_{a, s, lp, h} = \\
\text{Max} (0, ( \text{DaClrdHrlyQty}_{a, s, lp, h} - \sum_{t} \text{DaEnFinHrlyQty}_{a, s, lp, h, t} \\
- \sum_{t} \text{DaNEnFinHrlyQty}_{a, s, lp, h, t} \\
+ \sum_{i} \sum_{t} ( \text{DaImpExp5minQty}_{a, s, lp, i, t} / 12 ) ) )

(c.4) \ \text{DaSlNetWdrHrlyQty}_{s, h} = \\
\text{Max} (0, \sum_{a} \sum_{lp} [ \text{DaClrdHrlyQty}_{a, s, lp, h} + \sum_{t} \text{DaClrdVHrlyQty}_{a, s, lp, h, t} \\
+ \sum_{i} \sum_{t} ( \text{DaImpExp5minQty}_{a, s, lp, i, t} / 12 ) ] )
\]
(d) \[ \text{IF } \sum_{i} \text{DaLpNetWdrHrlyQty}_{a, s, lp, h} = 0 \]

THEN

\[ \text{DaLpIntSupplyHrlyFct}_{lp, h} = 0 \]

ELSE

\[ \text{DaLpIntSupplyHrlyFct}_{lp, h} = \]

\[ \text{Min} \left( 1, \sum_{i} \text{DaLpNetInjHrlyQty}_{a, s, lp, h} / \sum_{i} \text{DaLpNetWdrHrlyQty}_{a, s, lp, h} \right) \]

(d.1) \[ \text{IF } \text{DaAoNetInjSppHrlyQty}_{s, h} = 0 \]

THEN

\[ \text{DaLpNetInjHrlyQty}_{a, s, lp, h} = 0 \]

ELSE

\[ \text{DaLpNetInjHrlyQty}_{a, s, lp, h} = \text{DaSlNetInjHrlyQty}_{s, h} \]

* \( \text{DaAoNetInjHrlyQty}_{a, s, lp, h} / \text{DaAoNetInjSppHrlyQty}_{s, h} \)

(d.2) \[ \text{DaAoNetInjSppHrlyQty}_{s, h} = \sum_{lp} \sum_{a} \text{DaAoNetInjHrlyQty}_{a, s, lp, h} \]

(d.3) \[ \text{DaAoNetInjHrlyQty}_{a, s, lp, h} = \]

\[ (-1) \times \text{Min} \left( 0, (\text{DaClrdHrlyQty}_{a, s, lp, h} - \sum_{t} \text{DaEnFinHrlyQty}_{a, s, lp, h, t} \right. \]

\[ - \sum_{t} \text{DaNEnFinHrlyQty}_{a, s, lp, h, t} \]

\[ + \sum_{i} \sum_{t} \left( \text{DaImpExp5minQty}_{a, s, lp, i, t} / 12 \right) \) \]
(d.4) \( \text{DaSlNetInjHrlyQty}_{s, h} = \)

\[ \{ \text{Min} \left( 0, \sum_{lp} \sum_{a} \left[ \text{DaClrdHrlyQty}_{a, s, lp, h} + \sum_{t} \text{DaClrdVHrlyQty}_{a, s, lp, h, t} \right] \right) \} \right. \]

\[ + \sum_{i} \sum_{t} \left( \text{DaImpExp5minQty}_{a, s, lp, i, t} / 12 \right) \left. \} \times (-1) \}

(e) \quad \text{IF} \sum_{s} \text{DaLpNetInjHrlyQty}_{a, s, lp, h} = 0

\quad \text{THEN}

\quad \text{DaLpExtSupplyHrlyFct}_{lp, h} = 0

\quad \text{ELSE}

\quad \text{DaLpExtSupplyHrlyFct}_{lp, h} =

\quad \text{Max} \left[ 0, (1 - \left( \sum_{s} \text{DaLpNetWdrHrlyQty}_{a, s, lp, h} / \sum_{s} \text{DaLpNetInjHrlyQty}_{a, s, lp, h}\right)) \right] \}

(f) \quad \text{IF} \sum_{s} \text{DaLpNetInjHrlyQty}_{a, s, lp, h} = 0

\quad \text{THEN}

\quad \text{DaLpIwaMlcHrlyPrc}_{lp, h} = 0

\quad \text{ELSE}

\quad \text{DaLpIwaMlcHrlyPrc}_{lp, h} =

\quad \sum_{s} \text{DaLpNetInjHrlyQty}_{a, s, lp, h} \times \text{DaMlcHrlyPrc}_{s, h} \]
(g) \[ \text{DaSppIwaMlcHrlyPrc}_h = \sum_{s} \sum_{a} \left[ \text{DaLpExtSupplyHrlyFct}_{a, lp, h} \right] \]

\[ \times \sum_{s} \left( \text{DaLpNetInjHrlyQty}_{a, s, lp, h} \times \text{DaMlcHrlyPrc}_{s, h} \right) \]

\[ / \sum_{lp} \sum_{a} \left[ \text{DaLpExtSupplyHrlyFct}_{a, lp, h} \right] \text{MB35} \sum_{s} \text{DaLpNetInjHrlyQty}_{a, s, lp, h} \]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[ \text{DaOclDistDlyAmt}_{a, s, lp, d} = \sum_{h} \text{DaOclDistHrlyAmt}_{a, s, lp, h} \]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{DaOclDistAoAmt}_{a, m, d} = \sum_{s} \sum_{lp} \text{DaOclDistDlyAmt}_{a, s, lp, d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{DaOclDistMpAmt}_{m, d} = \sum_{a} \text{DaOclDistAoAmt}_{a, m, d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaOclDistHrlyAmt_{a, s, lp, h}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Over Collected Losses Distribution Amount per AO per Settlement Location per Loss Pool per Hour - The amount to AO a for AO a’s share of total over collection due to marginal losses at Settlement Location s in Loss Pool lp for the Hour.</td>
</tr>
<tr>
<td>DaNormLossRbtHrlyFct_{a, s, lp, h}</td>
<td>none</td>
<td>Hour</td>
<td>Day-Ahead Normalized Loss Rebate Factor per AO per Settlement Location per Loss Pool per Hour – AO a’s percentage rebate of the DaOclHrlyAmt_{h} at Settlement Location s in Loss Pool lp for the Hour.</td>
</tr>
<tr>
<td>DaLossRbtHrlyFct_{a, s, lp, h}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Loss Rebate Factor per AO per Settlement Location per Loss Pool per Hour – AO a’s amount of marginal loss dollars collected at Settlement Location s in Loss Pool lp for the Hour.</td>
</tr>
<tr>
<td>DaLossRbtSppHrlyFct_{h}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Loss Rebate Factor per Hour – The SPP total of DaLossRbtHrlyFct_{a, s, lp, h} for the Hour.</td>
</tr>
<tr>
<td>DaAoNetWdrSppHrlyQty_{s, h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Net Withdrawal Quantity per Hour – The SPP total of DaAoNetWdrHrlyQty_{a, s, lp, h} for the Hour.</td>
</tr>
<tr>
<td>DaAoNetInjSppHrlyQty_{s, h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Net Injection Quantity per Hour – The SPP total of DaAoNetInjHrlyQty_{a, s, lp, h} for the Hour.</td>
</tr>
<tr>
<td>DaOclHrlyAmt_{h}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Over Collected Losses Amount per Hour – The amount of over collection in the DA Market due to marginal losses for the Hour.</td>
</tr>
<tr>
<td>DaLpIntSupplyHrlyFct_{lp, h}</td>
<td>none</td>
<td>Hour</td>
<td>Day-Ahead Loss Pool Internal Supply Factor per Loss Pool per Hour – A ratio indicating the percentage of Loss Pool lp’s net withdrawals that are being served by net injections inside of Loss Pool lp.</td>
</tr>
<tr>
<td>DaLpExtSupplyHrlyFct_{lp, h}</td>
<td>none</td>
<td>Hour</td>
<td>Day-Ahead Loss Pool External Supply Factor per Loss Pool per Hour – A ratio indicating the percentage of Loss Pool lp’s net injections that are in excess of Loss Pool lp’s net withdrawals.</td>
</tr>
<tr>
<td>DaLpIwaMlcHrlyPrc_{lp, h}</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Loss Pool Injection Weighted Average Marginal Loss Component per Loss Pool per Hour - The weighted average DaMlcHrlyPrc_{x, h} for all injections in loss pool lp in Hour h.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaSppIwaMlcHrlyPrc&lt;sub&gt;_h&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead SPP Injection Weighted Average Marginal Loss Component per Hour - The weighted average DaMlcHrlyPrc&lt;sub&gt;_s, a&lt;/sub&gt; for all loss pool injections in excess of loss pool withdrawals in Hour &lt;sub&gt;_h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>DaLpNetInjHrlyQty&lt;sub&gt;_a, s, lp, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Injection Quantity per Settlement Location per Loss Pool per Hour – Asset Owner a’s net injection quantity at Settlement Location s in Loss pool lp in Hour &lt;sub&gt;_h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>DaAoNetInjHrlyQty&lt;sub&gt;_a, s, lp, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Injection Quantity per AO per Settlement Location per Loss Pool per Hour – Asset Owner a’s total injection quantity at Settlement Location s in Loss pool lp in Hour &lt;sub&gt;_h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>DaSlNetInjHrlyQty&lt;sub&gt;_s, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Injection Quantity per Settlement Location per Hour – Settlement Location s’s net injection quantity in Hour &lt;sub&gt;_h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>DaLpNetWdrHrlyQty&lt;sub&gt;_a, s, lp, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Withdrawal Quantity per Settlement Location per Loss Pool per Hour – Asset Owner a’s net withdrawal at Settlement Location s in Loss pool lp in Hour &lt;sub&gt;_h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>DaSlNetWdrHrlyQty&lt;sub&gt;_s, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Withdrawal Quantity per Settlement Location per Hour – Settlement Location s’s net withdrawal quantity for Hour &lt;sub&gt;_h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>DaAoNetWdrHrlyQty&lt;sub&gt;_a, s, lp, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Withdrawal Quantity per AO per Settlement Location per Loss Pool per Hour – Asset Owner a’s total withdrawal quantity at Settlement Location s in Loss Pool lp for Hour &lt;sub&gt;_h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>DaLmpHrlyPrc&lt;sub&gt;_s, h&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead LMP – The value described under Section 4.5.8.1 for AO &lt;sub&gt;_a&lt;/sub&gt; at Settlement Location s for Hour &lt;sub&gt;_h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>DaMccHrlyPrc&lt;sub&gt;_s, h&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Marginal Congestion Component of Day-Ahead LMP – The value described under Section 4.5.8.15 at Settlement Location s for Hour &lt;sub&gt;_h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>DaMlcHrlyPrc&lt;sub&gt;_s, h&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Marginal Losses Component of Day-Ahead LMP – The Marginal Losses Component of the Day-Ahead LMP at Settlement Location s for Hour &lt;sub&gt;_h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>DaClrdHrlyQty&lt;sub&gt;_a, s, lp, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Loss Pool per Hour in the DA Market – The value described under Section 4.5.8.1 for AO &lt;sub&gt;_a&lt;/sub&gt; at Settlement Location s in Loss Pool lp for Hour &lt;sub&gt;_h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>DaClrdVHrlyQty&lt;sub&gt;a, s, lp, h, t&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Virtual Energy Quantity per AO per Settlement Location per Transaction per Loss Pool per Hour in the DA Market – The value described under Section 4.5.8.3 for AO a at Settlement Location s in Loss Pool lp for transaction t for Hour h.</td>
</tr>
<tr>
<td>DaImpExp5minQty&lt;sub&gt;a, s, lp, i, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Interchange Transaction Quantity per AO per Settlement Location per Transaction per Loss Pool per Dispatch Interval – The value described under Section 4.5.8.2 for AO a at Settlement Location s in Loss Pool lp for transaction t for Dispatch Interval i.</td>
</tr>
<tr>
<td>DaOclDistDlyAmt&lt;sub&gt;a, s, lp, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Over Collected Losses Distribution Amount per AO per Settlement Location per Loss Pool per Operating Day- The amount to AO a for AO a’s share of total over collection due to marginal losses at Settlement Location s in Loss Pool lp for the Operating Day.</td>
</tr>
<tr>
<td>DaOclDistAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Over Collected Losses Distribution Amount per AO per Operating Day- The amount to AO a associated with Market Participant m for AO a’s share of total over collection due to marginal losses for the Operating Day.</td>
</tr>
<tr>
<td>DaOclDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Over Collected Losses Distribution Amount per MP per Operating Day- The amount to MP m for MP m’s share of total over collection due to marginal losses for the Operating Day.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>h</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>i</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>t</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Bilateral Settlement Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>lp</td>
<td>none</td>
<td>none</td>
<td>A Loss Pool.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.22  **Day-Ahead Demand Reduction Distribution Amount**

(1) A DA Market charge or credit\(^2\) will be calculated for each Asset Owner for each hour in which a Demand Response Resource was cleared in order to fund the credits paid under Section 4.5.8.1. The Asset Owner amount will be equal to the net distribution rate for Demand Reduction multiplied by the Asset Owners’ net DA Market cleared Energy withdrawals. The amount to each Asset Owner is calculated as follows:

\[
#\text{DaDRDistHrlyAmt}_{a, s, h} = \sum_i \text{DaDRLoadHrlyQty}_{a, s, h, i} \times \text{DaDRDistHrlyRate}_h
\]

Where:

(a) \(\#\text{DaDRLoadHrlyQty}_{a, s, h} = \max(0, \text{DaClrDrlryQty}_{a, s, h})\)

\[+ \sum_t \text{DaClrdVHrlyQty}_{a, s, h, t} + \sum_t \sum_i \text{DaImpExp5minQty}_{a, s, i, t} / 12\]

The cost allocation rate is calculated by dividing the total of all demand reduction credits by the total of allocation quantities.

(b) \(\#\text{DaDRDistHrlyRate}_h = \)

\[
\text{DaDRDistHrlyCost}_h / \text{DaDRDistHrlyQty}_h
\]

(b.1) \(\text{DaDRDistHrlyCost}_h = \)

\[
\sum_a \sum_s \text{DaDRHrlyAmt}_{a, s, h}
\]

(b.2) \(\text{DaDRDistHrlyQty}_h = \sum_a \sum_i \text{DaDRLoadHrlyQty}_{a, s, h}\)

\(^2\) Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettlement.
(2) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{DaDRDistAoAmt}_{a,m,d} = \sum_i \text{DaDRDistHrlyAmt}_{a,h}
\]

(3) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{DaDRDistMpAmt}_{m,d} = \sum_a \text{DaDRDistAoAmt}_{a,m,d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaDRDistHrlyAmt&lt;sub&gt;a, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Demand Reduction Distribution Amount per AO per Hour - The amount to AO &lt;i&gt;a&lt;/i&gt; for AO &lt;i&gt;a&lt;/i&gt;’s share of DA Market Demand Reduction costs per Settlement Location per Hour.</td>
</tr>
<tr>
<td>DaDRLoadHrlyQty&lt;sub&gt;a, s, h, [MCB38]&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Demand Reduction Load per AO per Settlement Location for Hour &lt;i&gt;h&lt;/i&gt; – Asset Owner &lt;i&gt;a&lt;/i&gt;’s load, virtual withdrawal and Export Interchange Transactions cleared in the DA Market at Settlement Location &lt;i&gt;s&lt;/i&gt; for Hour &lt;i&gt;h&lt;/i&gt; for use in Demand Reduction cost allocation.</td>
</tr>
<tr>
<td>DaDRDistHrlyRate&lt;sub&gt;[MCB39], h&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Demand Reduction Distribution Rate per Hour – The rate applied to AO &lt;i&gt;a&lt;/i&gt;’s Demand Reduction load in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaDRDistHrlyCost&lt;sub&gt;[MCB40], h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Demand Reduction Distribution Cost per Hour – The cost of Demand Reduction in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaDRDistHrlyQty&lt;sub&gt;[MCB41]&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Demand Reduction Distribution Quantity per Hour – The total zonal cost allocation quantity for Demand Reduction in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaDRHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Demand Reduction Amount per AO per Settlement Location per Hour - The value described under Section 4.5.8.21.</td>
</tr>
<tr>
<td>DaClrdHrlyQty&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.1 for AO &lt;i&gt;a&lt;/i&gt; at Settlement Location &lt;i&gt;s&lt;/i&gt; for Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaClrdVHrlyQty&lt;sub&gt;a, s, h, t&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Virtual Energy Quantity per AO per Transaction per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.3.</td>
</tr>
<tr>
<td>DaImpExp5minQty&lt;sub&gt;a, s, i, t&lt;/sub&gt;</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Interchange Transaction Quantity per AO per Transaction per Settlement Location per Dispatch Interval – The value described under Section 4.5.8.2.</td>
</tr>
<tr>
<td>DaDRDistAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Demand Reduction Distribution Amount per AO per Operating Day - The DA Market amount to AO &lt;i&gt;a&lt;/i&gt; associated with Market Participant &lt;i&gt;m&lt;/i&gt; for Demand Reduction for the Operating Day.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaDRDistMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Demand Reduction Distribution Amount per Market Participant per Operating Day - The DA Market amount to Market Participant &lt;i&gt;m&lt;/i&gt; for Demand Reduction for the Operating Day.</td>
</tr>
<tr>
<td>&lt;i&gt;a&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>&lt;i&gt;s&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>&lt;i&gt;h&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>&lt;i&gt;d&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>&lt;i&gt;m&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.1 Real-Time Asset Energy Amount

(1) The Real-Time Asset Energy Amount can be either a credit to an Asset Owner or a charge to an Asset Owner and is calculated on a net basis at each Settlement Location for:

(a) the difference between actual metered supply MWh amounts in a Dispatch Interval and cleared Resource Offers in the DA Market;

(b) the difference between actual metered demand MWh amounts in a Dispatch Interval and all cleared Demand Bids in the DA Market; and

(c) Real-Time Bilateral Settlement Schedules for Energy in a Dispatch Interval.

The net amount to each Asset Owner (AO) for each Settlement Location in a Dispatch Interval is calculated as follows:

\[
#RtEnergy5minAmt_{a,s,i} = RtLmp5minPrc_{s,i} \times [ (RtBillMtr5minQty_{a,s,i} - DaClrdHrlyQty_{a,s,h} ) - \sum_t RtEnFinHrlyQty_{a,s,t,h} ] / 12
\]

Where,

(a) The 5-minute billable meter determinant at the Settlement Location level is the sum of the 5-minute billable meter determinants at the Meter Data Submittal Location level as shown in the formula below. Most Settlement Locations will be comprised of only one Meter Data Submittal Location, but in certain cases a single Settlement Location will represent multiple Meter Data Submittal Locations, each of which is in a separate Settlement Area. Since the calibration function must be performed within Settlement Area boundaries, it is done before summing the data to the Settlement Location level. The 5-minute determinants are expressed in terms of levelized MW at both the Settlement Location and Meter Data Submittal Location level.

\[
RtBillMtr5minQty_{a,s,i} = \sum_{ml} RtMIBillMtr5minQty_{a,ml,i}
\]
The 5-minute billable meter determinant at the Meter Data Submittal Location level is the sum of the 5-minute adjusted meter determinant and the 5-minute calibration meter determinants at the Meter Data Submittal Location level as shown in the formula below. Both 5-minute determinants are expressed in terms of levelized MW.

\[
\text{RtMIBillMtr5minQty}_{a, ml, i} = \\
\text{RtAdjMtr5minQty}_{a, ml, i} + \text{RtCalMtr5minQty}_{a, ml, i}
\]

For Resource and load assets, the 5-minute adjusted meter determinant is a hierarchal selection among 1) 5-minute submitted actual meter reading, 2) profiled hourly submitted actual meter reading and 3) default 5-minute state estimator value. Registration will determine whether 5-minute or hourly meter submittals are permitted – it will not allow both for any given period. Under the Marginal Loss approach, it is assumed that meter submissions, with the exception of those with a “top-down load” relationship to the Settlement Area – generally those for which a top-down calculation is used – are net of transmission losses. Losses will be backed out of load submittals for the “top-down load”. For Demand Response Resources, the hierarchy is the same for submitted data, but instead of defaulting to the State Estimator data, the Resource output is calculated as the difference between a) the minimum of i) the hourly baseline load submitted for the Demand Response Load and ii) the State Estimator snapshot for the Demand Response Load for the 5 minute interval immediately preceding the first dispatch interval \((i = -1)\) and b) the Adjusted Meter Quantity for the DRL for each 5 minute interval. Registration will determine whether meter submittals are permitted or if the Demand Response resource must rely solely on the calculated resource output. For loads in which a Demand Response resource is imbedded within a Settlement Location, the response is added to the load meter data “grossing-up” the MW to avoid double counting of the response. In cases where load is calculated via a “top-down load” method (usually for the top-down load entity in the Settlement Area), gross-up is not necessary if the response is included with other generation from which interchange, metered load and losses are netted to achieve the submitted load introducing deviation between DA Market cleared Energy and the billable meter quantity. 5-minute adjusted meter, state estimator, SCADA and gross-up determinants are expressed in terms of levelized MW and both hourly and 5-minute submitted actual
determinants are in terms of MWh. The formula for the 5-minute adjusted meter determinant is shown below.

IF EXISTS \{ RtActMtr5minQty \ a, ml, i \} THEN

\[ \#RtAdjMtr5minQty \ a, ml, i = \]
\[ \text{RtActMtr5minQty} \ a, ml, i * 12 + \text{RtLoadGrossUp5minQty} \ a, \] \[\text{ml, i} \]
\[- \{ \text{IF TOPDOWNLOAD(ml)} \ \text{THEN RtSELoss5minQty} \ a, ml, \]
\[ \text{i} , \ \text{ELSE 0 } \} \]
ELSE

IF EXISTS \{ RtActMtrHrlyQty \ a, ml, h \} THEN

\[ \#RtAdjMtr5minQty \ a, ml, i = \text{RtSE5minQty} \ a, ml, i \]
+ \{ \text{RtActMtrHrlyQty} \ a, ml, h - \sum_{i} \text{RtSE5minQty} \ a, ml, \]
\[ i \ / 12 \}
\[ * \{ \text{IF } ( \sum_{i} \text{ABS} (\text{RtSE5minQty} \ a, ml, i ) > 0 \ \text{THEN} \text{ABS} (\text{RtSE5minQty} \ a, ml, \]
\[ i ) / \sum_{i} \text{ABS} (\text{RtSE5minQty} \ a, ml, i ) , \ \text{ELSE 1/12} \} * 12 \} \]
+ \text{RtLoadGrossUp5minQty} \ a, \] \[\text{ml, i} \]
\[- \{ \ \text{IF TOPDOWNLOAD(ml)} \ \text{THEN RtSELoss5minQty} \ a, ml, \]
\[ i , \ \text{ELSE 0 } \} \]
ELSE

IF \{ DRR \} THEN

\[ \#RtAdjMtr5minQty \ a, ml, i = \]
\[ \text{MAX } [\{ \text{MIN} (\text{RtBaseLineHrlyQty} \ a, ml(drl) , h , \text{RtSE5minQty} \ a, ml(drl), \ i = -1) \]
\[- \text{RtAdjMtr5minQty} \ a, ml(drl), i ) , 0 ] * (-1) \]
ELSE
The 5-minute load gross-up determinant is the inverse of the 5-minute adjusted meter determinant for the Demand Response resource which is behind the meter of the load. The 5-minute load gross-up determinant is expressed in terms of levelized MW. The formula for the 5-minute load gross-up determinant is shown below.

\[
#\text{RtLoadGrossUp5minQty}_{a, ml, i} = \sum_{ml(drr)} Rt\text{AdjMtr5minQty}_{a, ml(drr), i} \times (-1)
\]

The 5-minute calibration meter determinant is the hourly quantity, profiled by State Estimator data into 5-minute intervals as shown in the formula below. The 5-minute calibration meter determinant is expressed in terms of levelized MW. The formula for the 5-minute calibration meter determinant is shown below.

\[
#\text{RtCalMtr5minQty}_{a, ml, i} = \text{RtSE5minQty}_{a, ml, i} + \{ (\text{RtCalMtrHrlyQty}_{a, ml, h} - \sum_i \text{RtSE5minQty}_{a, ml, i} / 12) \times \frac{\text{ABS(\text{RtSE5minQty}_{a, ml, i})}}{\sum_i \text{ABS(\text{RtSE5minQty}_{a, ml, i})}} \times 12 \}
\]

The hourly calibration meter determinant is the weighted distribution of Settlement Area residual among load in the Settlement Area. The hourly calibration meter determinant is expressed in terms of levelized MW. The formula for the hourly calibration meter determinant is shown below.

\[
#\text{RtCalMtrHrlyQty}_{a, ml, h} = \frac{\text{RtResMtrHrlyQty}_{sa, h} \times \text{MAX}(\text{RtAdjMtrHrlyQty}_{a, ml, h, 0})}{\sum_{ml} \text{MAX}(\text{RtAdjMtrHrlyQty}_{a, ml, h, 0})}
\]
(g) The hourly adjusted meter determinant is the sum of the 5-minute adjusted meter determinant divided by 12. The hourly adjusted meter determinant is expressed in terms of levelized MW. The formula for the hourly adjusted meter determinant is shown below.

\[ \text{RtAdjMtrHrlyQty}_{a, ml, h} = \sum_i \text{RtAdjMtr5minQty}_{a, ml, i} / 12 \]

(h) The hourly residual load determinant is the net difference between generation & load, interchange and losses per Settlement Area. Hourly Net Actual Interchange is derived as the sum of the hourly metering submitted for aggregate ties between interconnected Settlement Areas. Missing tie values are assumed to be 0 replaced with State Estimator values [MCB54]. The hourly residual determinant is expressed in terms of levelized MW. The formula for the hourly residual load determinant is shown below.

\[ \text{RtResMtrHrlyQty}_{sa, h} = \left( \sum_a \sum_{ml} \text{RtAdjMtrHrlyQty}_{sa, a, ml, h} + \text{RtSaNetActIchngHrlyQty}_{sa, h} + \sum_i \text{RtSELoss5minQty}_{sa, i} / 12 \right) \times (-1) \]

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The amount is calculated as follows:

\[ \text{RtEnergyHrlyAmt}_{a, s, h} = \sum_i \text{RtEnergy5minAmt}_{a, s, i} \]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

\[ \text{RtEnergyDlyAmt}_{a, s, d} = \sum_h \text{RtEnergyHrlyAmt}_{a, s, h} \]

(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{RtEnergyAoAmt}_{a, m, d} = \sum_s \text{RtEnergyDlyAmt}_{a, s, d} \]
(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
RtEnergyMpAmt_{m,d} = \sum_{a} RtEnergyAoAmt_{a,m,d}
\]

(1) For FERC Electric Quarterly Reporting (EQR) purposes, SPP calculates net Dispatch Interval sales volume in excess of DA Market amounts and associated prices and calculates net Dispatch Interval purchases when Real-Time sales volume less than DA Market sales volume and associated prices that are associated with this Charge Type for each Asset Owner as follows:

(a) \( #EqrRtAssetEnergy5minQty_{a,s,i} = \)

\[
\text{Max} \ (0, -1 * \left( \text{RtBillMtr5minQty}_{a,s,i} - \text{DaClrdHrlyQty}_{a,s,h} \right) - \sum_{t} \text{RtEnFinHrlyQty}_{a,s,t,h} ) / 12 \}
\]

+ \{
\text{IF} #EqrDaAssetEnergyHrlyQty_{a,s,h} > 0 \ \text{THEN}
\]

\[
\text{Min} \ (0, -1 * \left( \text{RtBillMtr5minQty}_{a,s,i} - \text{DaClrdHrlyQty}_{a,s,h} \right) - \sum_{t} \text{RtEnFinHrlyQty}_{a,s,t,h} ) / 12 \}
\}

(b) \text{IF} #EqrRtAssetEnergy5minQty_{a,s,i} <> 0 \ \text{THEN}

\[
#EqrRtAssetEnergy5minPrc_{a,s,i} = \text{Rtlmp5minPrc}_{s,i}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtEnergy5minAmt $a, s, i$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Energy Amount per AO per Settlement Location per Dispatch Interval</strong> - The amount to AO $a$ for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids at Settlement Location $s$ for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtLmp5minPrc $s, i$</td>
<td>$/MW$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time LMP</strong> - The RTBM LMP at Settlement Location $s$ for Dispatch Interval $i$.</td>
</tr>
<tr>
<td>DaClrdHrlyQty $a, s, h$</td>
<td>MWh</td>
<td>Hour</td>
<td><strong>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market</strong> – The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>RtBillMtr5minQty $a, s, i$</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval</strong> - The Dispatch Interval metered quantities for AO $a$ Resources and load at Settlement Location $s$ in Dispatch Interval $i$ used by SPP for settlement purposes.</td>
</tr>
<tr>
<td>RtActMtr5minQty $a, ml, i$</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Actual Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval</strong> - The Dispatch Interval metered quantity, in MWh, for AO $a$’s Resources and load directly submitted by the Market Participant.</td>
</tr>
<tr>
<td>RtActMtrHrlyQty $a, ml, h$</td>
<td>MWh</td>
<td>Hour</td>
<td><strong>Real-Time Actual Meter Quantity per AO per Meter Data Submittal Location per Hour</strong> - The hourly metered quantity, in MWh, for AO $a$’s Resources and load directly submitted by the Market Participant.</td>
</tr>
<tr>
<td>RtMlBillMtr5minQty $a, ml, i$</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Billing Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval</strong> - The Dispatch Interval quantities adjusted to account for calibration Energy for AO $a$ load at Meter Location $ml$ in Dispatch Interval $i$.</td>
</tr>
<tr>
<td>RtCalMtr5minQty $a, ml, i$</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Calibration Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval</strong> - The Dispatch Interval calibration quantities calculated by SPP for AO $a$ at load at Meter Data Submittal Location $ml$ in Dispatch Interval $i$.</td>
</tr>
<tr>
<td>RtCalMtrHrlyQty $a, ml, h$</td>
<td>MWh</td>
<td>Hour</td>
<td><strong>Real-Time Calibration Meter Quantity per AO per Meter Settlement</strong></td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><code>RtLoadGrossUp5minQty</code> [MPRR77.55] <code>a, ml, i</code></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Load Gross Up per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval load gross up associated with a Demand Response Reserve for AO <code>a</code> at load Meter Data Submittal Location <code>ml</code> in Dispatch Interval <code>i</code>.</td>
</tr>
<tr>
<td><code>RtSE5minQty</code> <code>a, ml, i</code></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time State Estimator Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval State Estimator value for AO <code>a</code> at Meter Data Submittal Location <code>ml</code> in Dispatch Interval <code>i</code>.</td>
</tr>
<tr>
<td><code>RtBaseLineHrlyQty</code> <code>a, ml(drl), h</code></td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Base Line Load Quantity per AO per Demand Response Load Meter Data Submittal Location per Hour – The estimated consumption value associated with AO <code>a</code>’s Demand Response Load as submitted prior to Operating Hour <code>h</code>.</td>
</tr>
<tr>
<td><code>RtSELoss5minQty</code> <code>sa, i</code></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time State Estimator Losses per AO per Settlement Area per Dispatch Interval - The Dispatch Interval State Estimator total losses value for Settlement Area <code>sa</code> in Dispatch Interval <code>i</code>.</td>
</tr>
<tr>
<td><code>RtResMtrHrlyQty</code> <code>sa, h</code></td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Residual Load per Settlement Area per Hour - The hourly Residual Load for Settlement Area <code>sa</code> in Hour <code>h</code>.</td>
</tr>
<tr>
<td><code>RtSaNetActIchngHrlyQty</code> <code>sa, h</code></td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Net Actual Interchange per Settlement Area per Hour - The sum of hourly actual interchange values submitted for Settlement Area <code>sa</code> in Hour <code>h</code>.</td>
</tr>
<tr>
<td><code>RtAdjMtr5minQty</code> <code>a, ml, i</code></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Adjusted Actual Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval metered quantity, in MW, for AO <code>a</code>’s Resources and load calculated by SPP to account for load adjustments related to Demand Response Resources and to calculate a default value if <code>RtActMtrHrlyQty</code> <code>a, ml, h</code> or <code>RtAdjMtr5minQty</code> <code>a, ml, i</code> is not submitted.</td>
</tr>
<tr>
<td><code>RtAdjMtrHrlyQty</code> [MCB57] <code>a, ml, h</code></td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Adjusted Actual Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval metered quantity, in MW, for AO <code>a</code>’s Resources and load calculated by SPP to account for load adjustments related to Demand Response Resources and to calculate a default value if <code>RtActMtrHrlyQty</code> <code>a, ml, h</code> or <code>RtAdjMtr5minQty</code> <code>a, ml, i</code> is not submitted.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>---------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtEnFinHrlyQty</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Asset Bilateral Settlement Schedule for Energy per AO per Settlement Location per Transaction per Hour - The amount specified by the buyer AO and seller AO in an RTBM Bilateral Settlement Schedule for Energy at Asset Settlement Location s, for transaction t, for the Hour. The buyer AO amount is a positive value and the seller AO amount is a negative value.</td>
</tr>
<tr>
<td>RtEnergyHrlyAmt</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Energy Amount per AO per Settlement Location per Hour - The amount to AO a for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids at Settlement Location s for the Hour.</td>
</tr>
<tr>
<td>RtEnergyDlyAmt</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Energy Amount per AO per Settlement Location per Operating Day - The amount to AO a for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids at Settlement Location s for the Operating Day.</td>
</tr>
<tr>
<td>RtEnergyAoAmt</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Energy Amount per AO per Operating Day - The amount to AO a associated with Market Participant m for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids for the Operating Day.</td>
</tr>
<tr>
<td>RtEnergyMpAmt</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Energy Amount per MP per Operating Day - The amount to MP m for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids for the Operating Day.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>----------------------</td>
<td>------------</td>
</tr>
<tr>
<td>EqrRtAssetEnergy5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Asset Energy Transactions per AO per Settlement Location per Dispatch Interval– AO a’s RTBM Energy sale at Resource Settlement Location s in excess of the amount cleared Day-Ahead, net of Bilateral Settlement Schedules, in Dispatch Interval i or AO a’s RTBM Energy purchase at Resource Settlement Location s created when the actual Real-Time output is less than the amount cleared Day-Ahead, net of Financial Schedules, in Dispatch Interval i, for use by AO a in reporting such sales/purchases to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrRtAssetEnergy5minPrc&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Asset Energy Transactions Prices per AO per Settlement Location per Dispatch Interval – AO a’s prices associated with non-zero EqrRtAssetEnergy5minQty&lt;sub&gt;a, s, i&lt;/sub&gt; quantities in Dispatch Interval i for use by AO a in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>h</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>i</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>t</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Bilateral Settlement Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>ml(drr)</td>
<td>none</td>
<td>none</td>
<td>A Demand Response Resource Meter Data Submittal Location.</td>
</tr>
<tr>
<td>ml(drl)</td>
<td>none</td>
<td>none</td>
<td>A Demand Response Load Meter Data Submittal Location.</td>
</tr>
<tr>
<td>sa</td>
<td>none</td>
<td>none</td>
<td>A Settlement Area.</td>
</tr>
<tr>
<td>ml</td>
<td>none</td>
<td>none</td>
<td>A Meter Data Submittal Location.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.8  RUC Make-Whole-Payment Amount

(1) The RUC Make-Whole-Payment Amount is a credit or charge to a Resource Asset Owner and is calculated for each Resource with a RUC Commitment Period that was committed by SPP with an RTBM Resource Offer Commitment Status of “Market” or “Reliability” as defined under Section 4.2.2.1 or that was committed by a local transmission operator that SPP determines were selected in a non-discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of Attachment AE to the Tariff, are eligible to receive a RUC make whole payment. Resources issued commitment instructions by a local transmission operator in order to resolve a reliability issue may be eligible for make-whole-payments as defined in this Section if the selection of the Resource by the local transmission operator was performed in a non-discriminatory manner as determined by SPP; however, a manual process is employed for the calculations and the make-whole-payments will appear in the Miscellaneous Amount charge type defined in Section 4.5.11. A payment is made to the Resource Asset Owner when the sum of the Resource’s eligible RTBM Start-Up Offer costs, No-Load Offer costs, Energy Offer Curve and Operating Reserve Offer costs associated with actual MWh amounts for Energy and cleared RTBM Operating Reserve is greater than the Energy and Operating Reserve RTBM revenues received for that Resource over the Resource’s RUC Make-Whole-Payment Eligibility Period. Recovery of such compensation shall be collected in accordance with Section 8.6.7 of Attachment AE.

(2) A Resource’s RUC Make-Whole-Payment Eligibility Period is equal to the Resource’s RUC Commitment Period except as described below:

(a) As shown in Exhibit 4-20, for Resources with a RUC Commitment Period that begins in one Operating Day and ends in the next Operating Day, two RUC Make-Whole-Payment Eligibility Periods are created. The first period begins in the first Operating Day in the Dispatch Interval associated with the Resource’s RUC Commit Time and ends at the last Dispatch Interval of the first Operating Day. The second period begins in the first Dispatch Interval of the next Operating Day and ends in the Dispatch Interval associated with the Resource’s RUC De-Commit Time.

---

3 Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
Exhibit 4-1: RUC Make-Whole Payment Eligibility Period – Multiple Operating Days

(3) The following cost recovery eligible rules apply to each RUC Make-Whole-Payment Eligibility Period. Offer Resource production costs are calculated using the RTBM Offer prices in effect at the time the commitment decision was made for start-up, no-load, and minimum-energy; and the RTBM Offer prices in effect at the solving of a dispatch interval for incremental energy, Regulation-Up, Regulation-Down, Spin, and Supplement Reserves. [MCB62]

(a) If SPP cancels a start-up order prior to the start of the associated RUC Make-Whole-Payment Eligibility Period and the Resource is not a Synchronized Resource, the Asset Owner will receive reimbursement for a time-based pro-rata share of the Resource’s RTBM Start-Up Offer. Asset Owners may request additional compensation through submittal of actual cost documentation to the SPP. SPP will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

(b) In order to receive Start-Up Offer recovery within a RUC Make-Whole-Payment Eligibility Period, the Resource must be a Synchronized Resource for at least one Dispatch Interval in the RUC Make-Whole Payment Eligibility Period.

(c) In order to receive recovery of No-Load Offer costs in any Dispatch Interval in the RUC Make-Whole Payment Eligibility Period, the Resource must be a Synchronized Resource in that Dispatch Interval.

(d) There may be more than one RUC Make-Whole Payment Eligibility Period for a Resource in a single Operating Day for which a credit or charge is calculated. A
single RUC Make-Whole Payment Eligibility Period is contained within a single Operating Day.

(e) A Resource’s RTBM Start-Up Offer costs are not eligible for recovery in the following RUC Make-Whole Payment Eligibility Periods:

(i.) Any RUC Make-Whole Payment Eligibility Period that is adjacent to the end of a DA Market Make-Whole Payment Eligibility Period;

(ii.) Any RUC Make-Whole Payment Eligibility Period for which a Resource is a Synchronized Resource prior to this commitment period at a time one hour prior to that Resource’s RUC Commit Time less the Resource’s Sync-To-Min Time; and

(iii.) Any RUC Make-Whole Payment Eligibility Period resulting from a RUC Commitment Period that contains an hour for which the Resource Commitment Status is Self-Commit.

(f) For each RUC Make-Whole Payment Eligibility Period within an Operating Day, a Resource’s RTBM Start-Up Offer is divided by the lesser of (1) the Resource’s Minimum Run Time multiplied by 12 rounded down to the nearest whole interval or (2) 24 Hours multiplied by 12, and that portion of the Start-Up Offer is included as a cost in each interval of the RUC Make-Whole Payment Eligibility Period until the sum of these interval costs are equal to the RTBM Start-Up Offer or until the end of the RUC Make-Whole Payment Eligibility Period, whichever occurs first.

(g) To the extent that the full amount of the RTBM Start-Up Offer is not accounted for in the last RUC Make-Whole Payment Eligibility Period in the Operating Day, any remaining RTBM Start-Up Offer costs are carried forward for recovery in the first RUC Make-Whole Payment Eligibility Period of the following Operating Day provided that the Resource has not been committed in the DA Market in any hour of the first RUC Make-Whole Payment Eligibility Period as described in (h) below. For example, consider a Resource that is committed starting at 10:00 PM in Operating Day 1 that has a Minimum Run Time of 10 hours and a Start-Up Offer of $12,000. The RUC Commitment Period is from 10:00 PM in Operating Day 1 through 8:00 AM of Operating Day 2. For RUC Make-Whole Payment calculation purposes, the RUC Commitment Period is split into two separate RUC Make-Whole Payment Eligibility Periods as described in (2).a above. The first RUC Make-Whole Payment Eligibility Period will include $100/interval of Start-Up Offer costs ($12,000 / 120 intervals) in hour 23 and 24 intervals. The second
RUC Make-Whole Payment Eligibility Period will include $100/interval of Start-Up Offer costs in hours 1 through 8 intervals.

(h) If the Resource has been committed in the DA Market in a period adjacent to and following a RUC Make-Whole Payment Eligibility Period to the extent that the full amount of the RTBM Start-Up Offer is not accounted for in the RUC Make-Whole Payment Eligibility Period, any remaining RTBM Start-Up Offer costs are carried forward for recovery in the Day-Ahead Make-Whole Payment Eligibility Period.

(4) The amount to each Asset Owner (AO) for each eligible Resource Settlement Location for a given RUC Make-Whole Payment Eligibility Period is calculated as follows:

\[
#RtMwpCpAmt_{a,s,c} = (CncldStartAmt_{a,s,c} + \max(0, \{ \text{IF} \ (\text{CncldStartRatio}_{a,s,c} = 0, \text{THEN} \ 1, \text{ELSE} \ 0) \} \times \sum_i \{ \text{RtStartUpElig5minFlg}_{a,s,i,c} \times \text{RtStartUp5minAmt}_{a,s,i,c} \\
+ \text{RtRucComStat5minFlg}_{a,s,i,c} \times |\text{RtMwpCost5minAmt}_{a,s,i,c} \\\n+ \text{RtMwpRev5minAmt}_{a,s,i,c} \\\n+ \text{RtOom5minAmt}_{a,s,i} + \text{RtRegAdj5minAmt}_{a,s,i} \\
- \text{RtURDAj5minAmt}_{a,s,i,c} - \text{RtStatusAdj5minAmt}_{a,s,i,c} \\
- \text{RtLimitAdj5minAmt}_{a,s,i,c} \}) \} \}) \times (-1)
\]

Where,

(a) \#RtMwpCost5minAmt_{a,s,i,c} = \text{RtRucComStat5minFlg}_{a,s,i,c} * \\
(\text{RtIncrEn5minAmt}_{a,s,i} \\
+ \max(0, |\text{RtNoLoad5minAmt}_{a,s,i,c} \\
\text{- \text{IF} (DaClrdHrlyQty}_{a,s,h} < 0, \text{THEN} \text{DaNoLoadHrlyAmt}_{a,s,h,c} , \text{ELSE} \ 0 \}) \}
\]

\text{RtMinEn5minAmt}_{a,s,i,c}
+ RtRegUpAvail5minAmt_{a,s,i,c} + RtRegDnAvail5minAmt_{a,s,i,c} \\
+ RtSpinAvail5minAmt_{a,s,i,c} + RtSuppAvail5minAmt_{a,s,i,c} / 12

(a.1) IF \( \text{ABS (DaClrdHrlyQty}_{a,s,h}) \geq \text{ABS (RtBillMtr5minQty}_{a,s,i}) \) THEN \\
RtIncrEn5minAmt_{a,s,i} = 0
ELSE

\[ \#RtIncrEn5minAmt_{a,s,i} = \int \text{RTBM As Dispatched Energy Offer Curve} \]

Where:

\[ X = \text{Max (ABS (DaClrdHrlyQty}_{a,s,h}), \text{RtEffMin5minQty}_{a,s,i}) \]

AND

IF ControlStatus5minFlg_{a,s,i} = “Regulating” THEN \\
RtEffMin5minQty_{a,s,i} = \text{Min (}

\[ \text{RtComMinRegCapOL5minQty}_{a,s,i}, \]

\[ \text{RtDispMinRegCapOL5minQty}_{a,s,i}, \]

\[ \text{Max (0, (-1) * RtBillMtr5minQty}_{a,s,i} ) \]

ELSE
RtEffMin5minQty_{a,s,i} = \text{Min (}
\text{RtComMinEconCapOL5minQty}_{a,s,i},
\text{RtDispMinEconCapOL5minQty}_{a,s,i},
\text{Max (}0, (-1) \times \text{RtBillMtr5minQty}_{a,s,i}\text{)}
\text{AND}
\text{Y = Max (}(-1) \times \text{RtBillMtr5minQty}_{a,s,i}, 0\text{)}
\text{(a.2) IF } \text{ABS (DaClrdHrlyQty}_{a,s,h} > 0 \text{ THEN}
\text{RtMinEn5minAmt}_{a,s,i,c} = 0
\text{ELSE}
\text{# RtMinEn5minAmt}_{a,s,i,c} =
\int_{0}^{\text{RTBM As Committed Energy Offer Curve}}
\text{RtEffMin5minQty}_{a,s,i}
\text{(a.3) If } \text{RtRegUp5minQty}_{a,s,i} > \text{RtFixedRegUp5minQty}_{a,s,c,i} \text{ THEN}
\text{RtRegUpAvail5minAmt}_{a,s,i,c} =
\text{Max (}0, \lfloor \text{RtRegUp5minQty}_{a,z,s,i} - \sum_{z} \text{DaRegUpHrlyQty}_{a,z,s,h} \rfloor\text{)}
\text{* RtRegUpOffer}_{a,s,i,c}
ELSE

RtRegUpAvail5minAmt_{a,s,i} = 0

(a.4) If $RtRegDn5minQty_{a,s,i} > RtFixedRegDn5minQty_{a,s,c,i}$

THEN

RtRegDnAvail5minAmt_{a,s,i,c} =

$Max\left(0, \left[RtRegDn5minQty_{a,z,s,i} - \sum_{z} DaRegDnHrlyQty_{a,z,s,h}\right] \right) \times RtRegDnOffer_{a,s,i,c}$

ELSE

RtRegDnAvail5minAmt_{a,s,i} = 0

(a.5) If $RtSpin5minQty_{a,s,i} > RtFixedSpin5minQty_{a,s,c,i}$

THEN

RtSpinAvail5minAmt_{a,s,i,c} =

$Max\left(0, \left[RtSpin5minQty_{a,z,s,i} - \sum_{z} DaSpinHrlyQty_{a,z,s,h}\right] \right) \times RtSpinOffer_{a,s,i,c}$

ELSE

RtSpinAvail5minAmt_{a,s,i} = 0
(a.6) If \( \text{RtSupp5minQty}_{a,s,i} > \text{RtFixedSupp5minQty}_{a,s,c,i} \) 

THEN 

\[
\text{RtSuppAvail5minAmt}_{a,s,i,c} = \max(0, \sum \text{DaSuppHrlyQty}_{a,z,s,h} - \text{RtSupp5minQty}_{a,z,s,i}) \times \text{RtSuppOffer}_{a,s,i,c}
\]

ELSE 

\[
\text{RtSuppAvail5minAmt}_{a,s,i} = 0
\]

(b) \#RtMwpRev5minAmt_{a,s,i,c} = 

\[
\text{RtRucComStat5minFlg}_{a,s,i,c} \times \left[ ( \text{RtLmp5minPrc}_{s,i} \times \min(0, \text{RtBillMtr5minQty}_{a,s,i} - \text{DaClrdHrlyQty}_{a,s,h})) / 12 \right] + \text{RtRegUpRev5minAmt}_{a,s,i,c} + \text{RtRegDnRev5minAmt}_{a,s,i,c} + \text{RtSpinRev5minAmt}_{a,s,i,c} + \text{RtSuppRev5minAmt}_{a,s,i,c}
\]

(b.1) \text{RtRegUpRev5minAmt}_{a,s,i,c} = 

\[
(-1) \times \text{RtRucComStat5minFlg}_{a,s,i,c} \times (\max(0, \text{RtRegUp5minQty}_{a,z,s,i} - \sum \text{DaRegUpHrlyQty}_{a,z,s,h})) / 12
\]

(b.2) \text{RtRegDnRev5minAmt}_{a,s,i,c} =
(b.3) \( \text{RtSpinRev5minAmt}_{a,s,i,c} = \\
(\frac{-1}{12}) \times \text{RtRucComStat5minFlg}_{a,s,i,c} \\
\times (\text{Max}(0, \sum \text{DaSpinHrlyQty}_{a,z,s,h} - \text{RtSpin5minQty}_{a,z,s,i} \times \text{RtSpinMcp5minPrc}_{z,i}) / 12 \\
\)

(b.4) \( \text{RtSuppRev5minAmt}_{a,s,i,c} = \\
(\frac{-1}{12}) \times \text{RtRucComStat5minFlg}_{a,s,i,c} \\
\times (\text{Max}(0, \sum \text{DaSuppHrlyQty}_{a,z,s,h} - \text{RtSupp5minQty}_{a,z,s,i} \times \text{RtSuppMcp5minPrc}_{z,i}) / 12 \\
\)

(c) \( \#\text{CnclDStartAmt}_{a,s,c} = \\
\sum \text{RtStartUp5minAmt}_{a,s,i,c} \times \text{RtStartUpElig5minFlg}_{a,s,i,c} \times \text{CnclDStartRatio}_{a,s,c} \\
\times \text{CnclDStartRatio}_{a,s,c} = (\text{ElapsedTime}_{a,s,c} / \text{StartUpTime}_{a,s,c}) \\
\)
(d) In any Dispatch Interval in which the Resource has operated outside of its Operating Tolerance and that Resource has not been exempted from URD per Section 4.4.4.1, any incremental Energy costs associated with actual Energy output above the Resource’s Desired Dispatch is not eligible for recovery. The URD adjustment is calculated as follows:

\[
\text{IF } \text{ABS}(\text{URD5minQty}_{a,s,i}) > \text{ResOpTol5minQty}_{a,s,i} \text{ AND } \\
(\text{XmptDev5minFlg}_{a,s,i} = 0) \\
\text{THEN} \\
\text{#RtURDAj5minAmt}_{a,s,i,c} = \frac{\text{RtRucComStat5minFlg}_{a,s,i,c} \times \text{Max}(0, (\text{RtIncrEn5minAmt}_{a,s,i} - \text{RtDesiredEn5minAmt}_{a,s,i}))}{12} \\
\text{ELSE} \\
\text{RtURDAj5minAmt}_{a,s,i,c} = 0
\]

(d.1) \text{URD5minQty}_{a,s,i} = \\
(\text{RtBillMtr5minQty}_{a,s,i} \times (-1)) - \text{RtAvgSetPoint5minQty}_{a,s,i}

(d.2) \text{ResOpTol5minQty}_{a,s,i} = \\
\text{Min}(\text{URDMaxTol5minQty}_j, \text{Max}(\text{URDMinTol5minQty}_i, \\
\text{URDTol5minPct}_i \times \text{RtDispMaxEmerCapOL5minQty}_{a,s,i}))

(d.3) \text{IF } \text{RtDesiredEn5minQty}_{a,s,i} < \text{ABS}(\text{DaClrdHrlyQty}_{a,s,h}) \\
\text{THEN} \\
\text{#RtDesiredEn5minAmt}_{a,s,i} = \text{RtIncrEn5minAmt}_{a,s,i} \\
\text{ELSE} \\
\text{#RtDesiredEn5minAmt}_{a,s,i} = \int_{x}^{y} \text{RTBM As Dispatched Energy Offer Curve}

Where:

\[ X = \text{Max} \left( \text{ABS} \left( \text{DaClrdHrlyQty}_{a,s,h} \right), \text{RtEffMin5minQty}_{a,s,i} \right) \]

\[ Y = \text{Max} \left( X, \text{RtDesiredEn5minQty}_{a,s,i} \right) \]

(e) In any Dispatch Interval in which a Resource is in “Manual” status, any incremental Energy costs associated with actual Energy output above the Resource’s Desired Dispatch is not eligible for recovery. The status change adjustment is calculated as follows:

\[
\text{IF ControlStatus5minFlg}\_a, s, i = \text{“Manual”} \\
\text{AND} \text{ABS} \left( \text{URD5minQty}\_a, s, i \right) \leq \text{ResOpTol5minQty}\_a, s, i \\
\text{THEN} \\
\text{#RtStatusAdj5minAmt}\_a, s, i, c = \text{RtRucComStat5minFlg}\_a, s, i, c \\
* \text{Max} \left( 0, ( \text{RtIncrEn5minAmt}\_a, s, i - \text{RtDesiredEn5minAmt}\_a, s, i ) \right) / 12 \\
\text{ELSE} \\
\text{RtStatusAdj5minAmt}\_a, s, i, c = 0
\]

(f) In any Dispatch Interval in which a Resource has increased its Minimum Economic Capacity Operating Limit (or its Minimum Regulation Capacity Operating Limit if the Resource has cleared for Regulation-Up or Regulation-Down) above the Resource’s minimum limits used by SPP in the commitment decision or the minimum limits used to move from one configuration to another in the case of a Combined Cycle Resource, the Resource is not in “Manual” status and the increase in minimum limit is greater than the Resource’s Operating Tolerance, any incremental Energy costs associated with actual Energy output above the Resource’s Desired Dispatch is not eligible for recovery. The limit change adjustment is calculated as follows:

\[
\text{IF ControlStatus5minFlg}\_a, s, i \neq \text{“Regulating” AND} \\
\text{ControlStatus5minFlg}\_a, s, i \neq \text{“Manual” AND}
\]
(RtDispMinEconCapOL5minQty \ a, s, i

- RtComMinEconCapOL5minQty \ a, s, i > ResOpTol5minQty \ a, s, i \ AND

ABS (URD5minQty \ a, s, i ) <= ResOpTol5minQty \ a, s, i

THEN

#RtLimitAdj5minAmt \ a, s, i, c = RtRucComStat5minFlg \ a, s, i, c

* Max ( 0, ( RtIncrEn5minAmt \ a, s, i – RtDesiredEn5minAmt \ a, s, i ) / 12

ELSE IF

ControlStatus5minFlg \ a, s, i = “Regulating” \ AND

( RtDispMinRegCapOL5minQty \ a, s, i

- RtComMinRegCapOL5minQty \ a, s, i ) > ResOpTol5minQty \ a, s, i \ AND

ABS (URD5minQty \ a, s, i ) <= ResOpTol5minQty \ a, s, i

THEN

#RtLimitAdj5minAmt \ a, s, i, c = RtRucComStat5minFlg \ a, s, i, c

* Max ( 0, ( RtIncrEn5minAmt \ a, s, i – RtDesiredEn5minAmt \ a, s, i ) / 12

ELSE

RtLimitAdj5minAmt \ a, s, i, c = 0

(5) For each Asset Owner, a daily amount is calculated at each Settlement Location. The
daily amount is calculated as follows:

RtMwpDlyAmt \ a, s, d = \sum \ c \ RtMwpCpAmt \ a, s, c

(6) For each Asset Owner associated with Market Participant \ m, a daily amount is calculated.
The daily amount is calculated as follows:
\[ \text{RtMwpAoAmt}_{a, m, d} = \sum_i \text{RtMwpDlyAmt}_{a, s, d} \]

(7) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{RtMwpMpAmt}_{m, d} = \sum_i \text{RtMwpAoAmt}_{a, m, d} \]

(8) For FERC Electric Quarterly Reporting (“EQR”) purposes, SPP calculates RUC Make-Whole Payment $ per RUC Make-Whole-Payment Eligibility Period for each Asset Owner as follows:

(a) \[ \text{EqrRtMwp5minPrc}_{a, s, c} = (-1) \times \text{RtMwpCpAmt}_{a, s, c} \]

(b) IF \[ \text{EqrRtMwp5minPrc}_{a, s, c} > 0 \]

THEN

\[ \text{EqrRtMwp5minQty}_{a, s, c} = 1 \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>RtMwpCpAmt</strong>&lt;sub&gt;a, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td>RUC Make-Whole-Payment Amount per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period - The amount to AO a for RUC Make-Whole-Payment Eligibility Period c at Resource Settlement Location s.</td>
</tr>
<tr>
<td><strong>DaClrdHrlyQty</strong>&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour - The value described under Section 4.5.8.1 for AO a’s combined cycle resource at Settlement Location s for the Hour.</td>
</tr>
<tr>
<td><strong>RtStartUp5minAmt</strong>&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Real-Time Start-Up Cost Amount per AO per Settlement Location per Dispatch Interval per RUC Make-Whole-Payment Eligibility Period - The RTBM Start-Up Offer associated with AO a’s eligible Resource at Settlement Location s for RUC Make-Whole-Payment Eligibility Period c in Dispatch Interval i. This value is calculated by dividing <strong>RtStartUpAmt</strong>&lt;sub&gt;a, s, c&lt;/sub&gt; by the lesser of the Resource’s (<strong>RtMinRunTime</strong>&lt;sub&gt;a, i, s, c&lt;/sub&gt; *12) or (24 * 12). These interval values are carried forward into the following Operating Day, if needed, to ensure recovery of any remaining <strong>RtStartUpAmt</strong>&lt;sub&gt;a, s, c&lt;/sub&gt;.</td>
</tr>
<tr>
<td><strong>RtStartUpAmt</strong>&lt;sub&gt;a, s, c&lt;/sub&gt; (Not Available on Settlement Statement)</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Real-Time Start-Up Cost Amount per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period - The RTBM Start-Up Offer used in the commitment decision, associated with AO a’s eligible Resource at Settlement Location s for RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------------------</td>
<td>----------</td>
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<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtStartUpElig5minFlg_{a,s,i,c}</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>RUC Start-Up Recovery Eligibility Flag per AO per Resource Settlement Location per Dispatch Interval per RUC Make-Whole-Payment Eligibility Period – This flag is set equal to 1 in each Dispatch Interval of a RUC Make-Whole-Payment Eligibility Period where the Resource is eligible to recover start-up costs, or 0 where the Resource is not eligible to recover start-up costs.</td>
</tr>
<tr>
<td>RtRucComStat5minFlg_{a,s,i,c}</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>RUC Commitment Status Flag per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – This flag is set equal to 1 for each Dispatch Interval of a RUC Make-Whole-Payment Eligibility Period in which a Resource’s Commitment Status was “Market” or “Reliability”, or 0 if its Commitment Status was “Self”.</td>
</tr>
<tr>
<td>CncldStartRatio_{a,s,c}</td>
<td>None</td>
<td></td>
<td>Canceled Start Ratio per Resource Settlement Location in RUC Make-Whole-Payment Eligibility Period – The ratio of ElapsedTime_{a,s,c} to StartUpTime_{a,s,c} as calculated for each Dispatch Interval in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtMinRunTime_{a,i,s,c}</td>
<td>Time</td>
<td>Dispatch Interval</td>
<td>Real-Time Minimum Run Time per AO per Settlement Location Per Dispatch Interval per RUC Make-Whole-Payment Eligibility Period – The Minimum Run Time, in minutes, used in the commitment decision, associated with AO a’s eligible Resource at Settlement Location s for RUC Make-Whole-Payment Eligibility Period c as submitted as part of the RTBM Market Offer.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtSynchToMinTime_a, i, s, c</td>
<td>Time</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Synch To Minimum Time per AO per Settlement Location Per Dispatch Interval per RUC Make-Whole-Payment Eligibility Period</em> – The Synch To Minimum Time, in minutes, used in determining Start-Up Recovery Eligibility, associated with AO a’s eligible Resource at Settlement Location s for RUC Make-Whole-Payment Eligibility Period c as submitted as part of the RTBM Market Offer.</td>
</tr>
<tr>
<td>RtNoLoad5minAmt_a, i, s, c</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time No-Load Cost Amount per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</em> - The No-Load Offer used in the commitment decision, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtMwpCost5minAmt_a, s, i, c</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>RUC Make-Whole-Payment Cost per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</em> – The total Energy and Operating Reserve cost at actual Resource output, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtMwpRev5minAmt_a, s, i, c</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>RUC Make-Whole-Payment Revenue per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</em> – The total Energy and Operating Reserve revenue at actual Resource output, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
</tbody>
</table>


<table>
<thead>
<tr>
<th>Variable</th>
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<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>CnclStartAmt(_{a,s,c})</td>
<td>$</td>
<td>Eligibility Period</td>
<td><em>Real-Time Cancelled Start Amount per AO per Settlement Location per for the RUC Make-Whole-Payment Eligibility Period</em> – The Start-Up Offer cost reimbursement for an SPP cancelled start-up, in dollars, associated with AO (a)'s eligible Resource at Settlement Location (s) for RUC Make-Whole-Payment Eligibility Period (c).</td>
</tr>
<tr>
<td>ElapsedTime(_{a,s,c})</td>
<td>Time</td>
<td>Eligibility Period</td>
<td><em>Elapsed Time per AO per Settlement Location per for the RUC Make-Whole-Payment Eligibility Period</em> – The elapsed time, in minutes, between the start of a Resource’s StartUpTime(_{a,s,c}) and the time SPP cancelled the start-up, in dollars, associated with AO (a)'s eligible Resource at Settlement Location (s) for RUC Make-Whole-Payment Eligibility Period (c).</td>
</tr>
<tr>
<td>StartUpTime(_{a,s,c})</td>
<td>Time</td>
<td>Eligibility Period</td>
<td><em>Start-up Time per AO per Settlement Location for the RUC Make-Whole-Payment Eligibility Period</em> – The Start-Up Time, in minutes, used in the commitment decision associated with AO (a)'s eligible Resource at Settlement Location (s) for RUC Make-Whole-Payment Eligibility Period (c) as specified in the RTBM Offer submitted prior to the RUC Make-Whole-Payment Eligibility Period.</td>
</tr>
<tr>
<td>RtURDAj5minAmt(_{a,s,i,c})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>URD Adjustment per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</em> – The reduction in RUC Make-Whole Payment Amount associated with AO (a)'s eligible Resource at Settlement Location (s) for Dispatch Interval (i) in RUC Make-Whole-Payment Eligibility Period (c) when the Resource’s URD5minQty(<em>{a,s,i}) is outside of the Resource’s ResOpTol5minQty(</em>{a,s,i}).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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</tr>
<tr>
<td>URD5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation per AO per Settlement Location per Dispatch Interval – The Uninstructed Resource Deviation associated with AO a’s Resource at Settlement Location s in Dispatch Interval i.</td>
</tr>
<tr>
<td>ResOpTol5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Resource Operating Tolerance per AO per Settlement Location per Dispatch Interval – The Resource Operating Tolerance associated with AO a’s Resource at Settlement Location s in Dispatch Interval i.</td>
</tr>
<tr>
<td>URDMaxTol5minQty&lt;sub&gt;i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation Maximum Tolerance per Dispatch Interval – The maximum value of ResOpTol5minQty&lt;sub&gt;a, s, i&lt;/sub&gt; that is currently set at 20 MW.</td>
</tr>
<tr>
<td>URDMinTol5minQty&lt;sub&gt;i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation Minimum Tolerance per Dispatch Interval – The minimum value of ResOpTol5minQty&lt;sub&gt;a, s, i&lt;/sub&gt; that is currently set at 5 MW.</td>
</tr>
<tr>
<td>URDTol5minPct&lt;sub&gt;i&lt;/sub&gt;</td>
<td>Percent</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation Tolerance Percentage per Dispatch Interval – The percentage used to calculate the value of ResOpTol5minQty&lt;sub&gt;a, s, i&lt;/sub&gt; that is currently set at 5%.</td>
</tr>
<tr>
<td>RtAvgSetPoint5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Average Setpoint Instruction MW per AO per Settlement Location per Dispatch Interval – The average Setpoint Instruction over Dispatch Interval i for AO a’s Resource at Settlement Location s.</td>
</tr>
<tr>
<td>XmptDev5minFlg&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>URD Exemption Flag per AO per Resource Settlement Location per Dispatch Interval – A flag associated with AO a’s eligible Resource at Settlement Location s indicating that a Resource that has operated outside of its Operating Tolerance is or is not exempt from any associated penalty charges in Dispatch Interval i. If the flag is equal to zero, the Resource is not exempt. Otherwise, the flag will be set to a positive integer number which will indicate the reason of the exemption as specified under Section 4.4.4.1.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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</tr>
<tr>
<td>RtStatusAdj5minAmt (_a, s, i, c)</td>
<td>$</td>
<td>dispatch interval</td>
<td>Resource Status Change Adjustment per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period – The reduction in RUC Make-Whole Payment Amount associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c when the Resource’s Control Status is set to “Manual”.</td>
</tr>
<tr>
<td>ControlStatus5minFlg (_a, s, i)</td>
<td>None</td>
<td>dispatch interval</td>
<td>Control Status per AO per Settlement Location per Dispatch Interval – A Resource status indicator associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i as set by SPP operators that indicates the current dispatchable status of the Resource.</td>
</tr>
<tr>
<td>RtDispMaxEmerCapOL5minQty (_a, s, i)</td>
<td>MW</td>
<td>dispatch interval</td>
<td>Real-Time Maximum Emergency Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Maximum Emergency Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtEffMin5minQty (_a, s, i)</td>
<td>MW</td>
<td>dispatch interval</td>
<td>Real-Time Effective Minimum Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Effective Minimum Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtDispMinEconCapOL5minQty (_a, s, i)</td>
<td>MW</td>
<td>dispatch interval</td>
<td>Real-Time Minimum Economic Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Minimum Economic Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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<tr>
<td>RtDispMinRegCapOL5minQty (_{a, s, i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Minimum Regulation Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval</strong> – The Minimum Regulation Capacity Operating Limit associated with AO (a)'s eligible Resource at Settlement Location (s) for Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtLimitAdj5minAmt (_{a, s, i, c})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Resource Limit Change Adjustment per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</strong> – The reduction in RUC Make-Whole Payment Amount associated with AO (a)'s eligible Resource at Settlement Location (s) for Dispatch Interval (i) in RUC Make-Whole-Payment Eligibility Period (c) for a Real-Time increase in minimum limit.</td>
</tr>
<tr>
<td>RtComMinEconCapOL5minQty (_{a, s, i})</td>
<td>MW</td>
<td>Eligibility Period</td>
<td><strong>Real-Time Minimum Economic Capacity Operating Limit Quantity per AO per Settlement Location</strong> – The Minimum Economic Capacity Operating Limit associated with AO (a)'s eligible Resource at Settlement Location (s) for Dispatch Interval (i) as submitted in an RTBM Offer prior to the RUC Make-Whole-Payment Eligibility Period that was used in making the initial Resource commitment decision.</td>
</tr>
<tr>
<td>RtComMinRegCapOL5minQty (_{a, s, i})</td>
<td>MW</td>
<td>Eligibility Period</td>
<td><strong>Real-Time Minimum Regulation Capacity Operating Limit Quantity per AO per Settlement Location</strong> – The Minimum Regulation Capacity Operating Limit associated with AO (a)'s eligible Resource at Settlement Location (s) for Dispatch Interval (i) as submitted in an RTBM Offer prior to the RUC Make-Whole-Payment Eligibility Period that was used in making the initial Resource commitment decision.</td>
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<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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<tr>
<td>( \text{RtIncrEn5minAmt}_{a, s, i} )</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>\textit{Real-Time Incremental Energy Cost Amount per AO per Settlement Location per Dispatch Interval} - The average incremental energy offer cost, in dollars, associated with AO (a)'s\ eligible Resource at Settlement Location (s) for Dispatch Interval (i) from the Effective Minimum Capacity Operating Limit to ( \text{RtBillMtr5minQty}_{a, s, i} ).</td>
</tr>
<tr>
<td>( \text{RtMinEn5minAmt}_{a, s, i, c} )</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>\textit{Real-Time Energy Cost at Minimum Limit per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period} - The average incremental energy offer cost at the Effective Minimum Capacity Operating Limit associated with AO (a)'s\ eligible Resource at Settlement Location (s) for Dispatch Interval (i) in RUC Make-Whole-Payment Eligibility Period (c).</td>
</tr>
<tr>
<td>( \text{RtDesiredEn5minAmt}_{a, s, i} )</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>\textit{Real-Time Energy Cost at Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval} - The average incremental energy offer cost associated with AO (a)'s\ eligible Resource at Settlement Location (s) for Dispatch Interval (i), in dollars, from the Effective Minimum Capacity Operating Limit to ( \text{RtDesiredEn5minQty}_{a, s, i} ).</td>
</tr>
<tr>
<td>( \text{RtDesiredEn5minQty}_{a, s, i} )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>\textit{Real-Time Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval} – The Desired Dispatch MW for AO (a)'s\ eligible Resource for Dispatch Interval (i) at ( \text{RtLmp5minPrc}_{s, i} ) as calculated from the Resource’s As Dispatched Energy Offer Curve using the As-Committed Minimum Capacity Limit (Economic or Regulating, as applicable) as an output floor and the As-Committed Maximum Capacity Limit (Economic or Regulating, as applicable) as an output ceiling.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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</tr>
<tr>
<td>RtOom5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval - The value calculated under Section 4.5.9.9.</td>
</tr>
<tr>
<td>RtRegAdj5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation Deployment Adjustment Amount per AO per Resource Settlement Location per Dispatch Interval - The value calculated under Section 4.5.9.19.</td>
</tr>
<tr>
<td>RtRegUpOffer&lt;sub&gt;a, s, i, c&lt;/sub&gt; (Not Available on Settlement Statement)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Regulation-Up Offer associated with AO a’s Resource Settlement Location s at the time the commitment decision was made for Dispatch Interval i for RUC Make-Whole-Payment Eligibility Period c in Dispatch Interval i.</td>
</tr>
<tr>
<td>RtRegDnOffer&lt;sub&gt;a, s, i, c&lt;/sub&gt; (Not Available on Settlement Statement)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Down Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Regulation-Down Offer associated with AO a’s Resource Settlement Location s at the time the commitment decision was made for Dispatch Interval i for RUC Make-Whole-Payment Eligibility Period c in Dispatch Interval i.</td>
</tr>
<tr>
<td>RtSpinOffer&lt;sub&gt;a, s, i, c&lt;/sub&gt; (Not Available on Settlement Statement)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Spinning Reserve Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Spinning Reserve Offer associated with AO a’s Resource Settlement Location s at the time the commitment decision was made for Dispatch Interval i for RUC Make-Whole-Payment Eligibility Period c in Dispatch Interval i.</td>
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<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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</tr>
<tr>
<td><strong>RtSuppOffer (_{a, s, i, c})</strong> (Not Available on Settlement Statement)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Reserve Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Supplemental Reserve Offer associated with AO (a)'s Resource Settlement Location (s) at the time the commitment decision was made for Dispatch Interval (i) for RUC Make-Whole-Payment Eligibility Period (c) in Dispatch Interval (i).</td>
</tr>
<tr>
<td><strong>RtFixedRegUp5minQty (_{a, s, c, i})</strong></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Fixed Regulation-Up Quantity per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Fixed Regulation-Up MW specified in the Regulation-Up Offer associated with AO (a)'s Resource Settlement Location (s) at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period (c) in Dispatch Interval (i).</td>
</tr>
<tr>
<td><strong>RtFixedRegDn5minQty (_{a, s, c, i})</strong></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Fixed Regulation-Down Quantity per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Fixed Regulation-Down MW specified in the Regulation-Down Offer associated with AO (a)'s Resource Settlement Location (s) at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period (c) in Dispatch Interval (i).</td>
</tr>
<tr>
<td><strong>RtFixedSpin5minQty (_{a, s, c, i})</strong></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Fixed Spinning Reserve Quantity per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Fixed Spinning Reserve MW specified in the Spinning Reserve Offer associated with AO (a)'s Resource Settlement Location (s) at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period (c) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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<tr>
<td>RtFixedSupp5minQty&lt;sub&gt;a, s, c, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Fixed Supplemental Reserve Quantity per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</em> – The Fixed Supplemental Reserve MW specified in the Supplemental Reserve Offer associated with AO a’s Resource Settlement Location s at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period c in Dispatch Interval i.</td>
</tr>
<tr>
<td>RtRegUpAvail5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Regulation-Up Offer Cost Amount per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</em> - The Regulation-Up Offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtRegDnAvail5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Regulation-Down Offer Cost Amount per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</em> - The Regulation-Down Offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in DA Market Commitment Period c.</td>
</tr>
<tr>
<td>RtSpinAvail5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Spin Offer Cost Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</em> - The Spinning Reserve Offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
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<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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</tr>
<tr>
<td>RtSuppAvail5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Supplemental Offer Cost Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</em> - The Supplemental Reserve Offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtLmp5minPre&lt;sub&gt;s, i&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td><em>Real-Time LMP</em> - The value defined under Section 4.5.9.1 at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtBillMtr5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Actual Meter Quantity per AO per Location per Dispatch Interval</em> - The value defined under Section 4.5.9.1 for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtRegUpRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Regulation-Up Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</em> – The Real-Time incremental Regulation-Up revenue associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtRegDnRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Regulation-Down Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</em> – The Real-Time incremental Regulation-Down revenue associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtSpinRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Spinning Reserve Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</em> – The Real-Time incremental Spinning Reserve associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
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<td>Unit</td>
<td>Settlement Interval</td>
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<tr>
<td>RtSuppRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Reserve Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Real-Time incremental Supplemental Reserve revenue associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtMwpDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Amount per AO per Settlement Location per Operating Day - The RUC Make-whole amount to AO a for Operating Day d at Resource Settlement Location s.</td>
</tr>
<tr>
<td>RtMwpAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Amount per AO per Operating Day - The RUC Make-whole amount to AO a associated with Market Participant m for Operating Day d.</td>
</tr>
<tr>
<td>RtMwpMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Amount per MP per Operating Day - The RUC Make-whole amount to Market Participant m for Operating Day d.</td>
</tr>
<tr>
<td>EqrRtMwp5minPre&lt;sub&gt;a, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td>RUC Electric Quarterly Reporting Make-Whole-Payment Amount per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period - The RUC make-whole amount to AO a for RUC Make-Whole-Payment Eligibility Period c at Resource Settlement Location s for use by AO a in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements..</td>
</tr>
<tr>
<td>EqrRtMwp5minQty&lt;sub&gt;a, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td>RUC Electric Quarterly Reporting Make-Whole-Payment Quantity per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period – This value is set equal to 1 if EqrRtMwp5minPre&lt;sub&gt;a, s, c&lt;/sub&gt; &gt; 0 for use by AO a in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements..</td>
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<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
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<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>h</td>
<td>none</td>
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<tr>
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<td></td>
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<td>An Operating Day.</td>
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<tr>
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<td>none</td>
<td>A Settlement Location.</td>
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<tr>
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<td>none</td>
<td>A RUC Make-Whole-Payment Eligibility Period.</td>
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<tr>
<td>m</td>
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<td>none</td>
<td>A Market Participant.</td>
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</tbody>
</table>
4.5.9.9 Real-Time Out-Of-Merit Amount

(1) An RTBM credit or charge\(^4\) will be made to each Market Participant with a Resource that passes a primary Contingency Reserve deployment test as described under Section 6.1.11.1(3)(b)(i) and/or otherwise receives a Manual Dispatch Instruction from SPP or a local Transmission Operator that creates a cost to the Asset Owner or that adversely impacts the Asset Owner’s DA Market position and/or if a Market Participant must buy back its DA Market position for any Operating Reserve product at an RTBM MCP that is greater than that product’s DA Market MCP. Resources issued Manual Dispatch Instructions by a local transmission operator in order to solve a reliability issue may be eligible for out-of-merit credits as defined in this Section if the selection of the Resource by the Transmission Operator was performed in a non-discriminatory manner as determined by SPP; however, a manual process is employed for the calculation of the out-of-merit credits and they will appear in the Miscellaneous Amount charge type defined in Section 4.5.11.

The cost allocation of out-of-merit credits associated with Manual Dispatch Instructions issued by a local transmission operator to address a Local Reliability Issue will be determined hourly by multiplying an Asset Owner’s RTBM actual load in the Settlement Area by a rate determined by the dividing the daily sum of all out-of-merit credits associated with Local Reliability Issues in the Settlement Area by the daily sum of all Asset Owners’ RTBM actual load in the Settlement Area. A manual process is also employed for these calculations and the charges will appear in the Miscellaneous Amount charge type defined in Section 4.5.11. The amount will be calculated on a Dispatch Interval basis under the following conditions:

(a) If the Manual Dispatch Instruction is for Energy in the up direction and the Energy Offer Curve cost associated with the Out-Of-Merit-Energy (OOME) MW is greater than the RTBM LMP, the Asset Owner will receive a credit for the difference. The OOME MW is calculated as Max \((0, \text{ the difference between the absolute value actual Resource output and the Resource’s Desired Dispatch})\).

\(^4\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
the Resource’s Manual Dispatch Instruction and (ii) the Resource’s Desired Dispatch\textsuperscript{[MCRR11.67]};

(b) If the Manual Dispatch Instruction is for Energy in the down direction, including a Resource de-commitment and the RTBM LMP is greater than the DA Market LMP, the Asset Owner will receive a credit for the difference multiplied by the OOME MW. The OOME MW is calculated as Max (0, or the difference between the absolute value of the Resource’s DA Market cleared Energy MW and the absolute value of the actual Resource output). To the extent that the absolute value of actual Resource output is less than the Resource’s Manual Dispatch Instruction, a manual adjustment shall be performed to the OOME MW to ensure that the OOME MW is equal to Max (0, or the difference between (i) the absolute value of the Resource’s DA Market cleared Energy MW and (ii) the greater of the absolute value of actual Resource output or the Resource’s Manual Dispatch Instruction;\textsuperscript{[MCRR11.68]} and/or

(c) If the Manual Dispatch Instruction or a Resource de-commitment instruction, causes the RTBM cleared amount of an Operating Reserve product to be less than the DA Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the DA Market MCP, the Asset Owner will receive a credit for the difference multiplied by the Out-Of-Merit-Operating Reserve (OOMOR) MW. The OOMOR MW is calculated as Max (0, or the difference between the Resource’s DA Market cleared Operating Reserve MW and the Resource’s RTBM cleared Operating Reserve MW).

The settlement system is designed to flag conditions where manual adjustments are necessary to ensure that payments are limited to under-recovery. When they are identified, the Asset Owner will receive both a credit in the Real-Time Out-Of-Merit charge type and the adjustment charge in the Miscellaneous charge type.\textsuperscript{[MCRR11.69]} To the extent that additional costs are incurred as a direct result of a Manual Dispatch Instruction through the compensation mechanisms described above, Market Participants may request additional compensation through submittal of actual cost documentation to SPP. SPP will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

(d) The amount to each Asset Owner (AO) for each eligible Resource Settlement Location for each Dispatch Interval is calculated as follows:

\[
\text{IF } \text{RtOom5minFlg}_{a,s,i} = 1 \text{ OR ResDeCommit5minFlg}_{a,s,i} = 1
\]
THEN

\[
#RtOom5minAmt_{a,s,i} = (RtOomeIncr5minAmt_{a,s,i} + RtOomeDecr5minAmt_{a,s,i} + RtOomor5minAmt_{a,s,i} ) \times (-1)
\]

ELSE

\[
#RtOom5minAmt_{a,s,i} = 0
\]

Where,

(a) \[RtOomeIncr5minAmt_{a,s,i} = \max(0, RtDispIncrEn5minAmt_{a,s,i} - RtDispDesiredEn5minAmt_{a,s,i} + \min(0, RtBillMtr5minQty_{a,s,i} + RtDispDesiredEn5minQty_{a,s,i}) \times \max(0, RtLmp5minPrc_{s,i}) \) / 12\]

(a.1) \[#RtDispIncrEn5minAmt_{a,s,i} = \int_{x}^{y} \text{RTBM As Dispatched Energy Offer Curve}\]

Where:

IF ControlStatus5minFlg_{a,s,i} = “Regulating”

X = RtDispMinRegCapOL5minQty_{a,s,i}

ELSE

X = RtDispMinEconCapOL5minQty_{a,s,i}

AND
\[ Y = \text{Max} \left( X, \text{Max} \left( -1 \times \text{RtBillMtr5minQty}_{a,s,i}, 0 \right) \right) \]

(a.2) \#RtDispDesiredEn5minAmt_{a,s,i} = \int_y^{\text{RTBM}} \text{As Dispatched Energy Offer Curve}

Where:

IF ControlStatus5minFlg_{a,s,i} = \text{“Regulating”}

THEN

\[ X = \text{RtDispMinRegCapOL5minQty}_{a,s,i} \]

ELSE

\[ X = \text{RtDispMinEconCapOL5minQty}_{a,s,i} \]

AND

\[ Y = \text{Max} \left( X, \text{RtDispDesiredEn5minQty}_{a,s,i} \right) \]

(b) \text{RtOomeDecr5minAmt}_{a,s,i} = \text{Max} \left( 0, \text{RtBillMtr5minQty}_{a,s,i} - \text{DaClrdHrlyQty}_{a,s,h} \right) \times \text{Max} \left( 0, \text{RtLmp5minPrc}_{s,i} - \text{DaLmpHrlyPrc}_{s,h} \right) / 12

(c) \text{RtOomor5minAmt}_{a,s,i} = \sum_z \left( \text{Max} \left( 0, \sum_z \text{DaRegUpHrlyQty}_{a,z,s,h} - \text{RtRegUp5minQty}_{a,z,s,i} \right) \right) \times \text{Max} \left( 0, \text{RtRegUpMcp5minPrc}_{z,i} - \text{DaRegUpMcpHrlyPrc}_{z,h} \right) \right)
\[
+ \left( \max \left( 0, \sum_{i} DaRegDnHrlyQty_{a, z, s, h} - RtRegDn5minQty_{a, z, s, i} \right) \right) \times \left( \max \left( 0, RtRegDnMcp5minPrc_{z, i} - DaRegDnMcpHrlyPrc_{z, h} \right) \right)
\]
\[
+ \left( \max \left( 0, \sum_{i} DaSpinHrlyQty_{a, z, s, h} - RtSpin5minQty_{a, z, s, i} \right) \right) \times \left( \max \left( 0, RtSpinMcp5minPrc_{z, i} - DaSpinMcpHrlyPrc_{z, h} \right) \right)
\]
\[
+ \left( \max \left( 0, \sum_{i} DaSuppHrlyQty_{a, z, s, h} - RtSupp5minQty_{a, z, s, i} \right) \right) \times \left( \max \left( 0, RtSuppMcp5minPrc_{z, i} - DaSuppMcpHrlyPrc_{z, h} \right) \right)
\]
\]
\[
\] / 12
\]

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The hourly amount is calculated as follows:

\[
RtOomHrlyAmt_{a, s, h} = \sum_{i} RtOom5minAmt_{a, s, i}
\]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily credit amount is calculated as follows:

\[
RtOomDlyAmt_{a, s, d} = \sum_{h} RtOomHrlyAmt_{a, s, h}
\]

(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[
RtOomAoAmt_{a, m, d} = \sum_{s} RtOomDlyAmt_{a, s, d}
\]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
RtOomMpAmt_{m, d} = \sum_{a} RtOomAoAmt_{a, m, d}
\]
(6) For FERC Electric Quarterly Reporting ("EQR") purposes, SPP calculates Real-Time Out-of-Merit Energy and Operating Reserve $ per Dispatch Interval for each Asset Owner as follows:

(a) \#EqrRtOom5minPrc_{a,s,i} = (-1) \times \text{RtOom5minAmt}_{a,s,i}

(b) IF \#EqrRtOom5minPrc_{a,s,i} > 0

THEN

\#EqrRtOom5minQty_{a,s,i} = 1
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtOom5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval - The amount to AO a for eligible Resource Settlement Location s in Dispatch Interval i for Out-Of-Merit Energy and Operating Reserve resulting from an SPP Manual Dispatch Instruction.</td>
</tr>
<tr>
<td>RtOomeIncr5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Incremental Energy Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval - The portion of AO a’s RtOom5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt; amount for eligible Resource Settlement Location s in Dispatch Interval i for Out-Of-Merit Energy resulting from an SPP manual Dispatch Instruction in the up direction.</td>
</tr>
<tr>
<td>RtOomeDecr5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Decremental Energy Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval - The portion of AO a’s RtOom5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt; amount for eligible Resource Settlement Location s in Dispatch Interval i for Out-Of-Merit Energy resulting from an SPP manual Dispatch Instruction in the down direction.</td>
</tr>
<tr>
<td>ResDeCommit5minFlg&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Resource De-Commitment Flag per AO per Dispatch Interval per Settlement Location – The value as described under Section 4.5.9.10.</td>
</tr>
<tr>
<td>RtOom5minFlg&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-of-Merit Flag per AO per Settlement Location per Dispatch Interval – A flag that is set equal to 1 when SPP issues a Manual Dispatch Instruction or whenever there is a price correction event as described under Section 7, otherwise, this flag is set equal to zero.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------------</td>
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<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtOom5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Out-Of-Merit Operating Reserve Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval</strong> - The portion of AO a’s RtOom5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt; attributable to buying back a DA Market Operating Reserve position in the RTBM at an RTBM MCP that is greater than the corresponding DA Market MCP. This should not be a normal occurrence but could happen as a result of price corrections as described under Section 7.</td>
</tr>
<tr>
<td>RtDispDesiredEn5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval</strong> – The Desired Dispatch MW for AO a’s eligible Resource for Dispatch Interval i at RtLmp5minPrc&lt;sub&gt;s, i&lt;/sub&gt; as calculated from the Resource’s As Dispatched Energy Offer Curve using the As-Dispatched Minimum Capacity Limit (Economic or Regulating, as applicable) as an output floor and the As-Dispatched Maximum Capacity Limit (Economic or Regulating, as applicable) as an output ceiling.</td>
</tr>
<tr>
<td>RtDispIncrEn5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Incremental Energy Cost Amount per AO per Settlement Location per Dispatch Interval</strong> - The average incremental energy offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i as calculated from the Resource’s As Dispatched Energy Offer Curve from the As-Dispatched Minimum Capacity Limit (Economic or Regulating, as applicable) to the maximum of the As-Dispatched Minimum Capacity Limit or RtBillMtr5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;.</td>
</tr>
<tr>
<td>RtDispDesiredEn5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Energy Cost at Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval</strong> - The average incremental energy offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i as calculated from the Resource’s As Dispatched Energy Offer Curve from the As-Dispatched Minimum Capacity Limit (Economic or Regulating, as applicable) to the maximum of the As-Dispatched Minimum Capacity Limit or RtDispDesiredEn5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------</td>
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<td>---------------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtBillMtr5minQty&lt;sub&gt;a,s,i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Actual Meter Quantity per AO per Location per Dispatch Interval - The value defined under Section 4.5.9.1 for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtLmp5minPrc&lt;sub&gt;s,i&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time LMP - The value defined under Section 4.5.9.1 at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>DaClrdHrlyQty&lt;sub&gt;a,s,h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>DaRegUpHrlyQty&lt;sub&gt;a,z,s,h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.4.</td>
</tr>
<tr>
<td>DaRegDnHrlyQty&lt;sub&gt;a,z,s,h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.5.</td>
</tr>
<tr>
<td>DaSpinHrlyQty&lt;sub&gt;a,z,s,h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.6.</td>
</tr>
<tr>
<td>DaSuppHrlyQty&lt;sub&gt;a,z,s,h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.7.</td>
</tr>
<tr>
<td>RtRegUp5minQty&lt;sub&gt;a,z,s,i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Quantity per AO per Settlement Location per Dispatch Interval in the RTBM – The value described under Section 4.5.9.4.</td>
</tr>
<tr>
<td>RtRegDn5minQty&lt;sub&gt;a,z,s,i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Down Quantity per AO per Settlement Location per Dispatch Interval in the RTBM – The value described under Section 4.5.9.5.</td>
</tr>
<tr>
<td>RtSpin5minQty&lt;sub&gt;a,z,s,i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Spinning Reserve Quantity per AO per Settlement Location per Dispatch Interval in the RTBM – The value described under Section 4.5.9.6.</td>
</tr>
<tr>
<td>RtSupp5minQty&lt;sub&gt;a,z,s,i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Reserve Quantity per AO per Settlement Location per Dispatch Interval in the RTBM – The value described under Section 4.5.9.7.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------------------</td>
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<td>---------------------</td>
<td>---------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaRegUpMcpHrlyPrc ( \kappa, h )</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Market Clearing Price per Settlement Location per Hour in the DA Market— The value described under Section 4.5.8.4.</td>
</tr>
<tr>
<td>DaRegDnMcpHrlyPrc ( \kappa, h )</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Market Clearing Price per Settlement Location per Hour in the DA Market— The value described under Section 4.5.8.5.</td>
</tr>
<tr>
<td>DaSpinMcpHrlyPrc ( \kappa, h )</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Market Clearing Price per Settlement Location per Hour in the DA Market— The value described under Section 4.5.8.6.</td>
</tr>
<tr>
<td>DaSuppMcpHrlyPrc ( \kappa, h )</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Market Clearing Price per Settlement Location per Hour in the DA Market— The value described under Section 4.5.8.7.</td>
</tr>
<tr>
<td>RtRegUpMcp5minPrc ( \kappa, i )</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM— The value described under Section 4.5.9.4.</td>
</tr>
<tr>
<td>RtRegDnMcp5minPrc ( \kappa, i )</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Down Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM— The value described under Section 4.5.9.5.</td>
</tr>
<tr>
<td>RtSpinMcp5minPrc ( \kappa, i )</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Spinning Reserve Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM— The value described under Section 4.5.9.6.</td>
</tr>
<tr>
<td>RtSuppMcp5minPrc ( \kappa, i )</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Reserve Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM— The value described under Section 4.5.9.7.</td>
</tr>
<tr>
<td>RtOomHrlyAmt ( \kappa, s, h )</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per AO per Settlement Location per Hour - The amount to AO ( \kappa ) for eligible Resource Settlement Location ( s ) in Hour ( h ) for Out-Of-Merit Energy and Operating Reserve resulting from an SPP Manual Dispatch Instruction.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------</td>
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<td>---------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtOomDlyAmt (_{a, s, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per AO per Settlement Location per Operating Day - The amount to AO (a) for eligible Resource Settlement Location (s) in Operating Day (d) for Out-Of-Merit Energy and Operating Reserve resulting from an SPP Manual Dispatch Instruction.</td>
</tr>
<tr>
<td>RtOomAoAmt (_{a, m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per AO per Operating Day - The amount to AO (a) associated with Market Participant (m) in Operating Day (d) for Out-Of-Merit Energy and Operating Reserve resulting from an SPP Manual Dispatch Instruction.</td>
</tr>
<tr>
<td>RtOomMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per MP per Operating Day - The amount to MP (m) in Operating Day (d) for Out-Of-Merit Energy and Operating Reserve resulting from an SPP Manual Dispatch Instruction.</td>
</tr>
<tr>
<td>EqrRtOom5minPrc (_{a, s, i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting Out-of-Merit Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval - The Out-of-Merit make-whole amount to AO (a) for Dispatch Interval (i) at Resource Settlement Location (s) for use by AO (a) in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrRtOom5minQty (_{a, s, i})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting Out-of-Merit Make-Whole-Payment Quantity per AO per Settlement Location per Dispatch Interval – This value is set equal to 1 if (EqrRtOom5minPrc_{a, s, i} &gt; 0) for use by AO (a) in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
</tbody>
</table>

\(a\) none none An Asset Owner.
\(s\) none none A Settlement Location.
\(i\) none none A Dispatch Interval.
\(h\) none none An Hour.
\(d\) none none An Operating Day.
\(m\) none none A Market Participant.
4.5.9.25 **Real-Time Demand Reduction Distribution Amount**

(1) An RTBM Market charge or credit will be calculated for each Asset Owner for each hour in which a Demand Response Resource was dispatched in order to allocate the amounts calculated under Section 4.5.9.24. The Asset Owner amount will be equal to the net distribution rate for Demand Reduction multiplied by the Asset Owners’ actual real-time Energy withdrawals. The amount to each Asset Owner is calculated as follows:

\[ #\text{RtDRDistHrlyAmt}_{a,s,h} = \sum \text{RtDRLoadHrlyQty}_{a,s,i} * \text{RtDRDistHrlyRate}_{h} \]

**Where,**

(a) \( #\text{RtDRLoadHrlyQty}_{a,s,h} = \text{Max} (0, \sum \text{RtBillMtr5minQty}_{a,s,i}) \)

\[ + \text{Max} (0, \sum \sum \text{RtImpExp5minQty}_{a,s,i,t} * (1 - \text{RsgCrdFlg}_{t})) \]

The cost allocation rate is calculated by dividing the total of all demand reduction credits by the total of allocation quantities.

(b) \( #\text{RtDRDistHrlyRate}_{h} = \frac{\text{RtDRDistHrlyCost}_{h}}{\text{RtDRDistHrlyQty}_{h}} \)

(b.1) \( \text{RtDRDistHrlyCost}_{h} = \sum \sum \text{RtDRHrlyAmt}_{a,s,h} \)

(b.2) \( \text{RtDRDistHrlyQty}_{h} = \sum \sum \text{RtDRLoadHrlyQty}_{a,s,h} \)
(2) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{RtDRDistAoAmt}_{a, m, d} = \sum \text{RtDRDistHrlyAmt}_{a, h}
\]

(3) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{RtDRDistMpAmt}_{m, d} = \sum \text{RtDRDistAoAmt}_{a, m, d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtDRDistHrlyAmt&lt;sub&gt;a, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Demand Reduction Distribution Amount per Hour - The amount to AO&lt;sub&gt;a&lt;/sub&gt; for AO&lt;sub&gt;a&lt;/sub&gt;’s share of RTBM Demand Reduction costs per Settlement Location per Hour.</td>
</tr>
<tr>
<td>RtDRLoadHrlyQty&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Demand Reduction Load per AO per Settlement Location for Hour&lt;sub&gt;h&lt;/sub&gt; – Asset Owner&lt;sub&gt;a&lt;/sub&gt;’s load and Export Interchange Transactions in the RTBM at Settlement Location&lt;sub&gt;s&lt;/sub&gt; for Hour&lt;sub&gt;h&lt;/sub&gt; for use in Demand Reduction cost allocation.</td>
</tr>
<tr>
<td>RtDRDistHrlyRate&lt;sub&gt;h&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Real-Time Demand Reduction Distribution Rate per Hour – The rate applied to AO&lt;sub&gt;a&lt;/sub&gt;’s Demand Reduction load in Hour&lt;sub&gt;h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>RtDRDistHrlyCost&lt;sub&gt;h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Demand Reduction Distribution Cost per Hour – The cost of Demand Reduction in Hour&lt;sub&gt;h&lt;/sub&gt;.</td>
</tr>
<tr>
<td>RtDRHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Demand Reduction Amount per AO per Settlement Location per Hour - The value described under Section 4.5.9.24.</td>
</tr>
<tr>
<td>RtBillMtr5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The value described under Section 4.5.9.1.</td>
</tr>
<tr>
<td>RtlImpExp5minQty&lt;sub&gt;a, s, i, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval per Transaction – The value described under Section 4.5.9.2.</td>
</tr>
<tr>
<td>RsgCrdFlg&lt;sub&gt;t&lt;/sub&gt; (Not Available on Settlement Statement)</td>
<td>none</td>
<td>none</td>
<td>Reserve Sharing Group Contingency Reserve Deployment Flag per Event – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>RtDRDistAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Demand Reduction Distribution Amount per AO per Operating Day - The DA Market amount to AO&lt;sub&gt;a&lt;/sub&gt; associated with Market Participant&lt;sub&gt;m&lt;/sub&gt; for Demand Reduction for the Operating Day.</td>
</tr>
<tr>
<td>RtDRDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Demand Reduction Distribution Amount per Market Participant per Operating Day - The DA Market amount to Market Participant&lt;sub&gt;m&lt;/sub&gt; for Demand Reduction for the Operating Day.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>-------------------------</td>
</tr>
<tr>
<td>H</td>
<td>none</td>
<td>none</td>
<td>An Hour,</td>
</tr>
<tr>
<td>I</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval,</td>
</tr>
<tr>
<td>D</td>
<td>none</td>
<td>none</td>
<td>An Operating Day,</td>
</tr>
<tr>
<td>M</td>
<td>none</td>
<td>none</td>
<td>A Market Participant,</td>
</tr>
</tbody>
</table>
4.5.10.1 Transmission Congestion Rights Auction Transaction Amount

(1) A Transmission Congestion Rights auction charge or credit for each Asset Owner is calculated for each TCR instrument purchased or sold in the TCR auctions. The amount to each applicable Asset Owner for each auction and round is calculated as follows.

\[
#\text{TcrAucTxnDlyAmt}_{a, aid, d} = \sum_t \left\{ ( T\text{crAucQty}_{a, t, aid, source, sink} \times T\text{crAucPrc}_{aid, source, sink} ) \times T\text{crAucBuySellFlg}_{a, t} / \text{NumDaysInPeriod}_{aid} \right\}
\]

Where,

\[
T\text{crAucPrc}_{aid, source, sink} = \left[ \text{AuctionClearingPrice}_{aid, sink} - \text{AuctionClearingPrice}_{aid, source} \right]_{[JG74]}
\]

(2) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The net daily amount is calculated as follows:

\[
T\text{crAucTxnAoAmt}_{a, m, d} = \sum_{aid} T\text{crAucTxnDlyAmt}_{a, aid, d}
\]

(3) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
T\text{crAucTxnMpAmt}_{m, d} = \sum_a T\text{crAucTxnAoAmt}_{a, m, d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\text{TcrAucTxnDlyAmt}_{a, a\text{id}, d}$</td>
<td>$\text{$}$</td>
<td>Operating Day</td>
<td><em>Transmission Congestion Right Auction Daily Amount per AO per Auction ID per Operating Day</em> – The amount to AO $a$ for purchases and sales of TCRs for Operating Day $d$ for TCR auction ID $a\text{id}$.</td>
</tr>
<tr>
<td>$\text{TcrAucQty}_{a, t, a\text{id}, \text{source, sink}}$</td>
<td>$\text{\text{MW}}$</td>
<td>Month or Season</td>
<td><em>Transmission Congestion Right Quantity per AO per Transaction per Auction ID per Source and Sink</em> – AO $a$’s TCR quantity purchased or sold for each transaction $t$ in any TCR auction $a\text{id}$ at the associated source and sink point.</td>
</tr>
<tr>
<td>$\text{TcrAucPre}_{a\text{id}, \text{source, sink}}$</td>
<td>$\text{\text{$/MW}}$</td>
<td>Month or Season</td>
<td><em>Transmission Congestion Right Auction Clearing Price per Auction ID</em> – The TCR Auction clearing prices for TCR auction $a\text{id}$ at the associated source and sink point.</td>
</tr>
<tr>
<td>$\text{TcrAucBuySellFlg}_{a, t}$</td>
<td>none</td>
<td>Month or Season</td>
<td><em>Transmission Congestion Right Auction Buy/Sell Flag per AO per Transaction</em> – A flag indicating whether AO $a$’s $\text{TcrAucQty}_{a, t, a\text{id}, \text{source, sink}}$ was a purchase or a sale. This flag is set equal to +1 for purchases or to (+1) for sales.</td>
</tr>
<tr>
<td>$\text{NumDaysInPeriod}_{a\text{id}}$</td>
<td>none</td>
<td>none</td>
<td><em>Number of Days in the Period associated per Auction ID</em> – The number of Operating Days in month or seasons associated with TCR Auction ID $a\text{id}$.</td>
</tr>
<tr>
<td>$\text{AuctionClearingPrice}_{a\text{id, sink}}$</td>
<td>$\text{\text{$/MW}}$</td>
<td>Month or Season</td>
<td><em>TCR Auction Clearing Price per Auction ID at the Sink</em> - The Auction clearing prices for TCR auction $a\text{id}$ at the associated sink point.</td>
</tr>
<tr>
<td>$\text{AuctionClearingPrice}_{a\text{id, source}}$</td>
<td>$\text{\text{$/MW}}$</td>
<td>Month or Season</td>
<td><em>Auction Clearing Price per Auction ID at the Source</em> - The Auction clearing prices for TCR auction aid at the associated source point.</td>
</tr>
<tr>
<td>$\text{TcrAucTxnAoAmt}_{a, m, d}$</td>
<td>$\text{$}$</td>
<td>Operating Day</td>
<td><em>Transmission Congestion Right Auction Daily Amount per AO per Operating Day</em> – The amount to AO $a$ for purchases and sales of TCRs for Operating Day.</td>
</tr>
<tr>
<td>$\text{TcrAucTxnMpAmt}_{m, d}$</td>
<td>$\text{$}$</td>
<td>Operating Day</td>
<td><em>Transmission Congestion Right Auction Daily Amount per MP per Operating Day</em> – The amount to MP $m$ for purchases and sales of TCRs in the annual and monthly TCR Auctions for Operating Day $d$.</td>
</tr>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Bilateral Settlement Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$aid$</td>
<td>none</td>
<td>none</td>
<td>TCR Auction ID (separate ID for each round and type).</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
<tr>
<td>source</td>
<td>none</td>
<td>none</td>
<td>The Settlement Location identified as the source point for TCR $t$.</td>
</tr>
<tr>
<td>sink</td>
<td>none</td>
<td>none</td>
<td>The Settlement Location identified as the sink point for TCR $t$.</td>
</tr>
</tbody>
</table>
4.5.13.5 Final Settlement Statements

SPP will use settlement data to produce the final Settlement Statements for each Market Participant for the given Operating Day. Final Settlement Statements will be created at the end of the forty-seventh (47th) calendar day following the Operating Day. If the forty-seventh (47th) calendar day is not a Business Day, the final Settlement Statement is issued on the next Business Day thereafter. The final Settlement Statement will reflect the net changes to settlement charges generated on the Operating Day’s initial Settlement Statement.

4.5.15 Disputes

A Market Participant may dispute items set forth in any Settlement Statement (initial, final, or resettlement). The dispute must be filed on the Portal using the Contents of Notice dispute form as shown in Exhibit 4-23 with the following minimum content:

1. Statement type (initial, final, resettlement 1-12, ad hoc resettlement);
2. Charge type;
3. Estimated dispute amount in dollars;
4. Operating Day;
5. Start interval;
6. End interval;
7. Statement ID;
8. Transmission Customer;
9. Settlement Location;
10. Long description; and
11. Short description.

Proposed Tariff Language Revision

Attachment AE

5.1.2 Day-Ahead Market Execution

The Transmission Provider will employ a simultaneous co-optimization methodology to perform the following tasks in order to clear the Day-Ahead Market for each hour of the upcoming Operating Day:
Commit Offered Resources, Import Interchange Transaction Offers and Virtual Energy Offers using the SCUC algorithm to meet the Demand Bids, Virtual Energy Bids, Export Interchange Transactions Bids and Operating Reserve requirements on a least cost basis for each hour of the upcoming Operating Day.

(a) The Day-Ahead Market SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, including Resources committed in the Multi-Day Reliability Assessment, up to the Resources’ Maximum Economic Capacity Operating Limit or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up \( \text{and/or Regulation-Down} \) \(^{[MCB77]}\), and down to the Resources’ Minimum Economic Capacity Operating Limit or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down \( \text{and/or Regulation-Up} \) \(^{[MCB78]}\).

(i) If this capacity is not sufficient to meet the fixed Demand Bids and fixed Export Interchange Transaction Bids plus Operating Reserve requirements on a system-wide basis, the Day-Ahead Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

(ii) If there is a capacity surplus on a system-wide basis calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transaction Offers and the Regulation-Down requirement that is in excess of the sum of fixed Demand Bids and fixed Export Interchange Transaction Bids, the Day-Ahead Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed
Import Interchange Transaction Offers until the capacity surplus is eliminated; and (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limits for Resources not selected for Regulation-Down until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement.

(b) To the extent that a particular reliability issue cannot be directly addressed within the Day-Ahead Market SCUC algorithm as described under Subsections (i) and (ii) above, the Transmission Provider may manually commit Resources to alleviate such reliability issues. The Transmission Provider will re-run the Day-Ahead SCUC algorithm after such manual commitments, time permitting, and will notify the Market Participants that units were manually committed.

2) Using the Resource commitment results from the SCUC, clear Resource Offers, Virtual Energy Offers and Import Interchange Transaction Offers to meet Demand Bids, Virtual Energy Bids, Export Interchange Transaction Bids and Operating Reserve requirements on a least cost basis for each hour of the upcoming Operating Day using the SCED algorithm.

(a) The SCED algorithm includes marginal loss sensitivity factors that approximate the change in marginal system losses for a change in Energy dispatch.

(b) In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, the Transmission Provider must apply VRLs in SCED as described in Section 8.3.2 of this Attachment AE.

(c) The SCED algorithm will include product substitution logic as follows to clear Operating Reserve Offers:

(i) Any Regulation-Up Offers remaining once the Regulation-Up Requirement is satisfied may be used to meet Contingency Reserve
requirements if Regulation-Up Offer is more economic or is required to meet the overall Operating Reserve requirement;

(ii) Any Spinning Reserve Offers remaining once the Spinning Reserve Requirement is satisfied may be used to meet Supplemental Reserve requirements if Spinning Reserve Offer is more economic or is required to meet the overall Operating Reserve requirement; and

(iii) The product substitution logic ensures that the MCP for Regulation-Up is always greater than or equal to the Spinning Reserve MCP and that the Spinning Reserve MCP is always greater than or equal to the Supplemental Reserve MCP.

(d) Use of co-optimization logic will provide, through the Shadow Price calculation, MCPs for Operating Reserve that include any lost opportunity costs incurred as a result of Operating Reserve clearing.

5.2.2 Day-Ahead Reliability Unit Commitment Execution

The Transmission Provider will perform a capacity adequacy analysis for the upcoming Operating Day using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider load forecast and Operating Reserve requirements over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined in the submitted Energy Offer Curve.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, up to the Resources’ Maximum Economic Capacity Operating Limit or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up and/or Regulation-Down, and down to the Resources’
Minimum Economic Capacity Operating Limit or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down and/or Regulation-Up.

(a) If this capacity is not sufficient on a system-wide basis to meet the Transmission Provider load forecast plus Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement, to the extent possible.

(b) If there is a capacity surplus on a system-wide basis calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transaction Offers and the Regulation-Down requirement that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transaction Bids, the SCUC algorithm will, in priority order: (1) curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limits for Resources not selected for Regulation-Down until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement; (3) de-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and (4) de-commit self-committed Resources until the capacity surplus is eliminated.

(3) To the extent that a particular Transmission System security constraint cannot be directly addressed within the SCUC algorithm, the Transmission Provider may manually commit Resources and/or decommit self-committed Resources to
alleviate such a Transmission System security constraint in accordance with its authority as Reliability Coordinator.

(a) A reliability issue may arise within the operating area of a local transmission operator during the Day-Ahead Reliability Unit Commitment process. Such reliability issues may require out of merit commitment, decommitment, or dispatch instructions to be issued to one or more Resources to resolve the reliability issue. In such cases, the local transmission operator shall request the Transmission Provider to issue such instructions. To the extent that the Transmission Provider, at the request of a local transmission operator, issues instructions to a Resource to address a reliability issue, such Resource shall be eligible for compensation in the same manner as any other Resource. Recovery of such compensation shall be collected regionally as described under Section 8.6.7(A) of this Attachment AE, unless the Transmission Provider determines that the instructions were required for a Local Reliability Issue; in such case recovery of such compensation shall be collected locally as described under Section 8.6.7(B) of this Attachment AE.

6.1.2 Intra-Day Reliability Unit Commitment Execution

Using the inputs described in Section 6.1.1, the Transmission Provider will perform a capacity adequacy analysis using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider’s load forecast and Operating Reserve requirements over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined on the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the SCUC in making commitment decisions.
(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of thisAttachment AE, only including capacity up to the Resources’ Maximum Economic Capacity Operating Limits (or Maximum Regulation Capacity Operating Limits if selected for Regulation-Up [MCB83]) and down to the Resources’ Minimum Economic Capacity Operating Limits (or Minimum Regulation Capacity Operating Limits if selected for Regulation-Down [MCB84]).

(a) If this capacity is not sufficient on a system-wide basis to meet the Transmission Provider’s load forecast plus Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

(b) If there is a system-wide capacity surplus calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transaction Offers and the Regulation-Down requirement that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transaction Bids, the Day-Ahead Market SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) Incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limits until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement; (3) De-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is
eliminated; and (4) De-commit self-committed Resources until the capacity surplus is eliminated.

(3) To the extent that a particular reliability issue cannot be directly addressed within the SCUC algorithm as described under subsections (a) and (b) above, the Transmission Provider or local transmission operator may manually commit Resources and/or decommit self-committed Resources to alleviate such reliability issues in accordance with its authority as Reliability Coordinator.

(4) A Local Reliability Issue may arise within the operating area of a local transmission operator during the Intra-Day Reliability Unit Commitment Process. Such Local Reliability Issues may require out of merit commitment, decommitment, or dispatch instructions to be issued to one or more Resources to resolve the Local Reliability Issue. Time permitting, the local transmission operator shall request the Transmission Provider to issue such instructions. To the extent time does not permit, the local transmission operator may issue such instructions to the Resource. In such cases, the following shall take place:

(a) If initial instructions are issued by a local transmission operator, the transmission operator shall notify the Transmission Provider of the instructions given to the Resource.

(b) The transmission operator and Transmission Provider will coordinate to ensure subsequent instructions are provided by the Transmission Provider.

(c) The transmission operator shall log such instructions, and shall notify the Transmission Provider of such action. The Transmission Provider shall log such instructions as manual commitment, decommitment, or OOME Dispatch instruction, as appropriate, as if it gave such instruction to the Resource.

(d) The Resource shall be eligible to receive the compensation for such instructions in the same manner as if it had been committed by the Transmission Provider; provided that the Transmission Provider determines that the Resource selected in response to such instructions was selected in a non-discriminatory manner. Such determination shall be made using the standards and procedures set forth in Section 6.1.2.1 of this Attachment AE. If the Transmission Provider determines
that instructions were issued to resolve a Local Reliability Issue, recovery of such compensation shall be collected locally as described under Section 8.6.7(B) of this Attachment AE.

(5) In the event that the local transmission operator issues instructions to a Resource to resolve an issue other than a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by the Transmission Provider; provided that the Transmission Provider determines that the Resource selected in response to such instructions was selected in a non-discriminatory manner. Such determination shall be made using the standards and procedures set forth in Section 6.1.2.1 of this Attachment AE. Recovery of such compensation shall be collected regionally as described under Section 8.6.7(A) of this Attachment AE.

(6) In the event that the Transmission Provider issues instructions to a Resource at the request of a local transmission operator to resolve a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by the Transmission Provider. Recovery of such compensation shall be collected locally as described under Section 8.6.7(B) of this Attachment AE.

(7) In the event that the Transmission Provider issues instructions to a Resource at the request of a local transmission operator to resolve an issue other than a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by the Transmission Provider. Recovery of such compensation shall be collected regionally as described under Section 8.6.7(A) of this Attachment AE.

6.4.1 Uninstructed Resource Deviation

The following rules apply to the calculation of Uninstructed Resource Deviation (“URD”).

(1) A Market Participant with Resources registered at a Common Bus will be aggregated and treated as a single Resource and the For the purposes of determining URD exemptions for Resources that are part of a Common Bus as
described under Section 6.4.1.1(6) of this attachment AE, each Asset Owner’s Resources’ combined average ramped MW Setpoint Instruction and the Resources’ combined actual average MW output at the Common Bus will be used to calculate URD calculation purposes at the Common Bus for the Dispatch Interval for each Asset Owner.

(2) A Resource’s URD is allocated a portion of the RUC make whole payment costs, as described under Section 8.6.7 of this Attachment AE, in any Dispatch Interval where Resource’s URD is outside of its Operating Tolerance unless that Resource has been exempted from URD.

(a) A generating unit Resource’s Operating Tolerance in each Dispatch Interval is equal to the Resource’s Maximum Emergency Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(b) A Dispatchable Demand Response Resource’s Operating Tolerance in each Dispatch Interval is equal to the resource’s Maximum Emergency Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(c) A Block Demand Response Resource’s Operating Tolerance in each Dispatch Interval is equal to the resource’s Maximum Economic Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(d) The Common Bus Operating Tolerance for each Market Participant registered at a Common Bus is equal to the sum of that Market Participant’s Resources’ Maximum Emergency Capacity Operating Limits for Resources that are on-line multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(e) If the absolute value of a Resource’s URD is greater than the Resource’s Operating Tolerance in any Dispatch Interval, the Resource URD / 12 is included in the hourly allocation of RUC make whole payment cost allocation. The Hourly URD amount is calculated as the sum of Dispatch
Interval URD for the hour. Additionally, if that Resource was eligible to receive a RUC make whole payment, the payment may be reduced in accordance with Section 8.6.5 of this Attachment AE.

### 6.4.1.1 Uninstructed Resource Deviation Exemptions

A Resource’s URD in a Dispatch Interval will be considered equal to zero (0) under the following situations:

1. The Resource is deployed for Contingency Reserve as described in Section 6.3.2 of this Attachment AE or is deployed for a Contingency Reserve test as described under Sections 2.10.1 and 2.10.2 of this Attachment AE; or
2. The Resource trips off-line or is derated after receiving Dispatch Instructions; or
3. There is missing or bad Resource SCADA data in the Dispatch Interval; or
4. If during Emergency Conditions the URD is due to a Resource output above the Resource’s Setpoint Instruction in a shortage condition or the URD is due to a Resource output below the Resource’s Setpoint Instruction during an excess generation condition; or
5. If a Dispatch Instruction is issued to a Resource beyond the reported capabilities due to the application of a VRL; or
6. If the Resource is part of a Common Bus and the URD calculated at the Common Bus is less than the Operating Tolerance calculated at the Common Bus;
7. If the URD results from an event of force majeure or, in the case of a Variable Energy Resource, if the URD results from extremely high wind or other extreme weather-related conditions materially and directly impacting a Variable Energy Resource’s ability to provide Energy. For purposes of this subsection, the term force majeure shall have the meaning described under Section 10.1 of this Tariff except that acts of Curtailment shall not qualify for exemption. The Market Participant must provide the Transmission Provider with adequate documentation through the invoice dispute process in order for the Market Participant to be eligible to avoid such URD. The Transmission Provider will determine through the dispute process whether such URD should be waived; or
8.6.5 Reliability Unit Commitment Make Whole Payment Amount

(1) Asset Owners of Resources committed by the Transmission Provider with an RTBM Resource Offer commitment status as defined under Sections 4.1(10)(b) and (c) of this Attachment AE or committed by a local transmission operator that the Transmission Provider determines were selected in a non-discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, are eligible to receive a RUC make whole payment. A RUC make whole payment is made to the Asset Owner when the sum of a Resource’s eligible RTBM Start-Up Offer costs, No-Load Offer costs, Energy Offer Curve and Operating Reserve Offer costs associated with actual Energy and cleared RTBM Operating Reserve is greater than the Energy and Operating Reserve RTBM revenues received over the Resource’s RUC make whole payment eligibility period. Resources that are committed by a local transmission operator that the Transmission Provider determines were selected in a discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, are not eligible to receive compensation under this Section 8.6.5.

(2) A Resource’s RUC make whole payment eligibility period is equal to that Resource’s RUC Commitment Period. For Resources with a RUC Commitment Period that begins in one Operating Day and ends in the next Operating Day, two RUC make whole payment eligibility periods are created. The first period begins in the first Operating Day in the Dispatch Interval associated with the Resource’s RUC Commit Time and ends at the last Dispatch Interval of the first Operating Day. The second period begins in the first Dispatch Interval of the next Operating Day and ends in the Dispatch Interval associated with the Resource’s RUC De-Commit Time.

(3) The following cost recovery rules apply to each RUC make whole payment eligibility period. *Offer*—Resource production costs are calculated using the
RTBM Offer prices in effect at the time the commitment decision was made for start-up, no-load, and minimum-energy; and the RTBM Offer prices in effect at the solving of a dispatch interval for the Energy above minimum energy, Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve.

(a) If the Transmission Provider cancels a Commitment Instruction prior to the start of the associated RUC make whole payment eligibility period and the Resource is not a Synchronized Resource, the Asset Owner will receive reimbursement for a time-based pro-rata share of the Resource’s RTBM Start-Up Offer. Asset Owners may request additional compensation through submittal of actual cost documentation to the Transmission Provider. The Transmission Provider will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

(b) In order to receive the full amount of Start-Up Offer recovery within a RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in at least one Dispatch Interval in the RUC make whole payment eligibility period.

(c) In order to receive recovery of No-Load Offer costs in any Dispatch Interval in the RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in that Dispatch Interval.

(d) There may be more than one RUC make whole payment eligibility period for a Resource in a single Operating Day. A single RUC make whole payment eligibility period is contained within a single Operating Day.

(e) A Resource’s RTBM Start-Up Offer costs are not eligible for recovery in the following RUC make whole payment eligibility periods:

   (i) Any RUC make whole payment eligibility period that is adjacent to the end of a Day-Ahead Market make whole payment eligibility period;
(ii) Any RUC make whole payment eligibility period for which a Resource is a Synchronized Resource prior to this commitment period at a time one (1) hour prior to that Resource’s RUC Commit Time less the Resource’s Sync-To-Min Time; and

(iii) Any RUC make whole payment eligibility period resulting from a RUC Commitment Period that contains an hour for which the Resource was self-committed.

(f) For each RUC make whole payment eligibility period within an Operating Day, a Resource’s RTBM Start-Up Offer is divided by the lesser of (1) the Resource’s Minimum Run Time multiplied by twelve (12), rounded down to the nearest whole interval, or (2) twenty-four (24) hours multiplied by twelve (12), and that portion of the Start-Up Offer is included as a cost in each interval of the RUC make whole payment eligibility period until the sum of these interval costs are equal to the RTBM Start-Up Offer or until the end of the RUC make whole payment eligibility period, whichever occurs first.

(g) To the extent that the full amount of the RTBM Start-Up Offer is not accounted for in the last RUC make whole payment eligibility period in the Operating Day, any remaining RTBM Start-Up Offer costs are carried forward for recovery in the first RUC make whole payment eligibility period of the following Operating Day provided that the Resource has not been committed in the Day-Ahead Market in any hour of the first RUC make whole payment eligibility period as described in (h) below.

(h) If the Resource has been committed in the Day-Ahead Market in a period adjacent to and following a RUC make whole payment eligibility period to the extent that the full amount of the RTBM Start-Up Offer is not accounted for in the RUC make whole payment eligibility period, any remaining RTBM Start-Up Offer costs are carried forward for recovery in the Day-Ahead make whole payment eligibility period.
(i) If a Resource has operated outside of its Operating Tolerance in any Dispatch Interval, any cost associated with energy output above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Subsection 4(c) below.

(j) If a Resource becomes non-dispatchable in any Dispatch Interval, any cost associated with energy output above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Subsection 4(c) below.

(k) If a Resource’s minimum operating limit is increased above the Resource’s minimum operating limit that was used to make the commitment decision, the increase is greater than the Resource’s Operating Tolerance and the Resource remains dispatchable in any Dispatch Interval, any cost associated with energy output above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Subsection 4(c) below.

(4) The payment to each Asset Owner for each eligible Settlement Location for a given RUC make whole payment eligibility period is calculated as follows:

RUC Make Whole Payment Amount =

Maximum of [Either Zero or (RUC Make Whole Payment Cost Amount in the RUC Make Whole Payment Eligibility Period + RUC Make Whole Payment Revenue Amount in the RUC Make Whole Payment Eligibility Period – Uninstructed Resource Deviation Cost Disallowance – Non-Dispatchable Cost Disallowance – Minimum Limit Cost Disallowance)]

(a) An Asset Owner’s RUC Make Whole Payment Cost Amount for each eligible Resource is equal the sum for all Dispatch Intervals in the RUC Make Whole Payment Eligibility Period of (i) Start-Up Offer used to make commitment decision, (ii) No-Load Offer used to make commitment decision, (iii) Energy cost at minimum output as calculated from the
Energy Offer Curve used to make commitment decision, (iv) Energy cost above minimum output as calculated from the Energy Offer Curve that applied to the current Dispatch Interval, and (v) Operating Reserve cost associated with cleared Real-Time Operating Reserve as calculated from the Operating Reserve Offers except that Operating Reserve costs associated with self-scheduled Operating Reserve where such self-schedules are less than or equal to the amount of Operating Reserve cleared shall be set equal to zero.

(b) An Asset Owner’s RUC Make Whole Payment Revenue Amount for each eligible Resource is equal the sum for all hours in the RUC Make Whole Payment Eligibility Period of (i) revenue associated with Energy calculated by multiplying actual Energy by Real-Time LMP (ii) the sum of the revenues calculated under Section 8.6.2, 8.6.3 and 8.6.4 of this Attachment AE for that eligible Resource and (iii) Energy revenue associated with payments made under Section 8.6.6 of this Attachment AE and (iv) amounts associated with settlement made under Section 8.6.15 of this Attachment AE.

(c) An Asset Owner’s Uninstructed Resource Deviation Cost Disallowance, Non-Dispatchable Cost Disallowance, or Minimum Limit Cost Disallowance is equal to the positive difference between the Resource’s Energy cost at actual output as calculated from the Resource’s current Dispatch Interval Energy Offer Curve and the Resource’s Energy cost at the Resource’s economic operating point as calculated from the Resource’s current Dispatch Interval Energy Offer Curve.

(d) A Resource’s economic operating point is the MW output where the cost on the Resource’s current Dispatch Interval Energy Offer Curve is equal to the Real-Time LMP for that Resource.

8.6.6 Real-Time Out-of-Merit Amount
An RTBM OOME payment will be made for each Asset Owner with a Resource that passes a primary Contingency Reserve deployment test as described in Section 2.10.1 of this Attachment AE and/or receives a Transmission Provider Manual Dispatch Instruction that creates a cost to the Asset Owner or that adversely impacts the Asset Owner’s Day-Ahead Market position for Energy and/or Operating Reserve. Resources issued a Manual Dispatch Instruction by a local transmission operator that the Transmission Provider determines were selected in a discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, are not eligible to receive a RTBM OOME payment. The amount will be calculated on a Dispatch Interval basis as follows:

1. If the Manual Dispatch Instruction is for Energy in the up direction and the Energy Offer Curve cost associated with the Resource’s additional output attributable to its response (“OOME MW”) is greater than the RTBM LMP multiplied by the OOME MW, the Asset Owner will receive a payment for the difference. The payment shall be limited to the amount necessary to compensate the Asset Owner for any under-recovery resulting from its Resource’s response to the Manual Dispatch Instruction. The OOME MW is calculated as the positive difference between (i) the lesser of the actual Resource output or the Resource’s Manual Dispatch Instruction MW and (ii) the Resource’s economic operating point. The Resource’s economic operating point is calculated as described under Section 8.6.5(4)(d);

2. If the Manual Dispatch Instruction is for Energy in the down direction, including a Resource de-commitment and the RTBM LMP is greater than the Day-Ahead Market LMP, the Asset Owner will receive a payment equal to the difference multiplied by the Resource’s reduction in output attributable to its response (“OOME MW”). The payment shall be limited to the amount necessary to compensate the Asset Owner for any increase in net settlement costs resulting from its response to the Manual Dispatch Instruction. The OOME MW is calculated as the maximum of zero (0) or the difference between the Resource’s
Day-Ahead Market cleared Energy MW and the greater of (i) actual Resource output or (ii) the Resource’s Manual Dispatch Instruction MW;

(3) If the Manual Dispatch Instruction or a Resource de-commitment instruction, causes the RTBM cleared amount of an Operating Reserve product to be less than the Day-Ahead Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the Day-Ahead Market MCP, the Asset Owner will receive a payment for the difference multiplied by the OOME Operating Reserve MW. The OOME Operating Reserve MW is calculated as the maximum of zero (0) or the difference between the Resource’s Day-Ahead Market cleared Operating Reserve MW and the Resource’s RTBM cleared Operating Reserve MW.

(4) To the extent that additional costs are incurred as a direct result of a Manual Dispatch Instruction that are not addressed through the compensation mechanisms described in (1) through (3) above, Asset Owners may request additional compensation through submittal of actual cost documentation to the Transmission Provider. The Transmission Provider will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

8.7.1 Transmission Congestion Rights Auction Transaction Amount

A TCR auction daily charge or payment to each Asset Owner is calculated as the sum of charges and payments associated with that Asset Owner’s TCRs purchased or sold on a particular source to sink path, for each TCR auction period and round in the annual and monthly TCR auctions, as follows:

TCR Auction Daily Amount =

Sum of [(TCR Auction Quantity) * (Auction Clearing Price at Sink - Auction Clearing Price at Source) / Number of Days in the Period]

(1) An Asset Owner’s TCR Quantity is the total MWs of TCRs purchased on a particular source to sink path in the annual TCR auctions or the net total MWs of
TCRs purchased or sold on a particular source to sink path in round 1 and round 2 in the monthly TCR auctions by that Asset Owner.

(2) Auction Clearing Price at SourceSink is the Auction Clearing Price in the applicable auction period and round at the sink-source Settlement Location of the TCR Quantity source to sink path as calculated as described under Section 7.3.4 and 7.4.4 of this Attachment AE.

(3) Auction Clearing Price at SourceSink is the Auction Clearing Price in the applicable auction period and round at the source-sink Settlement Location of the TCR Quantity source to sink path as calculated as described under Section 7.3.4 and 7.4.4 of this Attachment AE.

(4) Number of Days in the Period is either number of days in the applicable monthly period or number of days in the applicable seasonal period.

10.3 Invoice Disputes

In the event that a dispute arises between the Market Participant and the Transmission Provider concerning any initial, final or resettlement Settlement Statements contained within an invoice that cannot be resolved to the Market Participant’s satisfaction, such disputes shall be resolved as follows:

(1) In the case of a dispute relating to an initial or final Settlement Statement, the Market Participant must notify the Transmission Provider within ninety (90) calendar days following the issue date of the applicable invoice of the items that the Market Participant wishes to dispute. In the case of resettlement statements, the Market Participant must notify the Transmission Provider within thirty (30) calendar days following the issue date of the applicable invoice of the items contained in that statement that the Market Participant wishes to dispute, which issues must relate to incremental changes in data that occurred between issuance of the final Settlement Statement and the first (1st) resettlement statement or between resettlement statements.

The notice of dispute must contain the following minimum information:
• Statement type (initial, final, resettlement, ad hoc resettlement [MCB93])
• Charge type
• Estimated dispute amount in dollars
• Operating Day
• Start interval
• End interval
• Market Participant
• Asset Owner
• Settlement Location
• Long description
• Short description.

(2) If the Transmission Provider determines that additional information is required concerning a submitted notice of dispute, the Transmission Provider shall notify the Market Participant no later than thirty (30) days following the date the notice of dispute was submitted to the Transmission Provider. The Market Participant must then submit additional information to the Transmission Provider within thirty (30) days in order to have the notice of dispute considered valid.

(3) The Transmission Provider shall use its best efforts to notify the Market Participant of approval or denial of the submitted notice of dispute within twenty (20) business days following the close of the applicable ninety (90) day or thirty (30) day window specified under Subsection 10.3(1) or Subsection 10.3(2). If the Transmission Provider estimates that it will take longer than the twenty (20) business day window to analyze a specific billing dispute, the Transmission Provider shall notify the Market Participant and provide an estimate of the amount of time required to complete the analysis.

(4) If the Transmission Provider denies a Market Participant’s notice of dispute or the Market Participant is not satisfied that it is receiving timely consideration of the dispute, the Market Participant may initiate the dispute resolution procedures specified under Section 12 of the Tariff.
Proposed Criteria Language Revision

N/A
## PRR Recommendation Report

<table>
<thead>
<tr>
<th>PRR No.</th>
<th>Marketplace-PRR138</th>
<th>PRR Title</th>
<th>Long-Term Congestion Rights</th>
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### Timeline

- ☐ Normal
- ☒ Expedited
- ☐ Urgent Action

Provide explanation if Expedited and/or Urgent Action is selected: This MPRR is expedited so that it can be reviewed by all working groups before it goes to the October MOPC.

### Recommendation Action

- ☒ Approve
- ☐ Reject
- ☐ Require additional information
- ☐ Defer
- ☐ Refer

### Impact Analysis Required

- ☐ Yes – If yes, estimated cost:
- ☒ No

SPP Staff will complete this section.

### Protocol Section(s) Requiring Revision

**Section No.**: 1.0, 3.2, 5.0, 5.1, 5.1.1, 5.1.2, 5.1.3, 5.2 (new), 5.2.1 (new), 5.2.2 (new), 5.2.3 (new), 5.2.4 (new), 5.2.5 (new), 5.2.6 (new), 5.3, 5.3.1, 5.3.2, 5.3.3, 5.3.4, 5.4, 5.4.1, 5.4.2, 5.4.3, 5.4.4, 5.5, 5.5.1, 5.5.2, 5.5.3, 5.5.4, 5.6, 5.6.1, 5.6.2, 5.6.3, 5.7,


**Protocol Version**: 15.0a

### Type of Revision

- ☐ Correction/Clean-Up
- ☐ Clarification
- ☒ Design Enhancement
- ☐ Design Change

### Timeline

- ☐ Go-Live
- ☒ Post Go-Live

### Revision Description

Modifications were made to the TCR Markets processes to incorporate the addition of Long-Term Congestion Rights.

In the October, 2013 FERC Order approving the Integrated Marketplace Filing, FERC required SPP to implement Long-Term Congestion Rights is compliance with FERC Order 681 180 days following Integrated Marketplace go-live. This MPRR is meant to comply with FERC’s directive.
## Tariff Implications or Changes

- **Yes – Section No:** *(Include a summary of impact and/or specific changes)*


## Criteria Impact or Changes

- **No – Section No:** *(Include a summary of impact and/or specific changes)*

- **No**

## MWG Review

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## RTWG Review

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<th>Date of Vote: 8/22/2013</th>
<th>Vote: Approved subject to MWG corresponding protocol changes. Two Abstentions – AEP and Empire.</th>
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<td>Date of Vote: 9/25/2013</td>
<td>Vote: Approved SPP Comments</td>
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## ORWG Review

| Date of Vote: 8/30/2013 | Vote: Approved with no Reliability Impact |

## CAWG Review

| Date of Vote: 9/4/2013 | Vote: CAWG recommends the RSC approve MPRR 138 |

## RSC Review

| Date of Vote:          | Vote:                                        |

## MOPC Recommendation

| Date of Vote:          | Vote:                                        |

## Board Review

| Date of Vote:          | Vote:                                        |

## Date

| 7/19/2013 |
### Sponsor

<table>
<thead>
<tr>
<th>Name</th>
<th>Debbie James on behalf of the Long-Term Congestion Rights Task Force</th>
</tr>
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<tbody>
<tr>
<td>E-mail Address</td>
<td><a href="mailto:djames@spp.org">djames@spp.org</a></td>
</tr>
<tr>
<td>Company</td>
<td>Southwest Power Pool</td>
</tr>
<tr>
<td>Phone Number</td>
<td>501.614.3577</td>
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### Comments Received

<table>
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<tr>
<th>Comment Author</th>
<th>Marguerite Wagner</th>
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<tr>
<td>Date</td>
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<th>Comment Description</th>
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<td>Following up on the presentation that Edison Mission Marketing &amp; Trading gave at the LTCR TF on Monday (thank you to the group for giving us time on the agenda)--presentation is at:</td>
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we are proposing some edits to the LTCR TF Work Group PRR up for consideration at the MWG next week. While the LTCR TF has not seen these edits (due to the timing of our edits), we still believe that it would be best to try to address this issue in the stakeholder process if we can--and we would welcome an opportunity to further discuss at MWG.

**The issue:**

- Providing only a choice of Revenue Credits for Market Participant Funded Incremental Upgrades does not incent a valuable small scale transmission upgrades (which are supported in FERC Guideline 3 for rights made available for transmission expansions). This is the case because if a non-Transmission owner funds an upgrade to relieve economic congestion, to recover the investment such an investor would have to wait until sufficient new requests for network service resulted in payments to them.
- The reason to encourage small scale investments by non-Transmission Owners--they relieve congestion at no cost to consumers--thus lowering overall costs of congestion (and the investment is paid for by the Market Participant--so consumers do not pay for the transmission upgrade).
- To encourage such investments, we believe that Market Participants should have a choice for a MP Funded Incremental Upgrade--to receive either Revenue Credits or LTCRs (not both).

**Proposed Solution:**

Develop an SPP approved process to award LTCRs commensurate with some percentage of transfer capability created through incremental transmission investment undertaken by a non-TO Market Participant.

**Fundamental Tenets of Market Participant Funded Incremental Upgrade LTCRs:**

1) The process would be documented in a business practice document developed with stake-holder input.
2) Market participants would work with SPP and the Transmission Owners to accomplish the upgrade.
2) LTCRs awarded as a result of the MP funded upgrade would expire after a period of years (specifics to be determined)

4) Market Participant would have the choice of source/sink pair and MW capped at the delta of transmission capability arising from the upgrade—as approved by SPP

To this end, we propose language in the NPRR (included in the attached document as track changes and further highlighted in yellow to make it very clear) that we believe would provide the flexibility to continue to develop this concept. We commit to being engaged in the discussions and appreciate your consideration of this issue.

Given the timing, I have taken the liberty to send out to the MWG as well as the Protocol Revision list serve—and I plead for indulgence ahead of time.

Kind regards,

Marguerite

Comment Status
Comments were taken into consideration. MWG did not make any changes based on the comments received.

Comments Received

<table>
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<tr>
<th>Comment Author</th>
<th>Brenda Fricano on behalf of the RTWG</th>
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<td>Date</td>
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<tr>
<td>Comment Description</td>
<td>RTWG made grammatical changes to the Tariff language. RTWG made other changes to include capitalization, punctuation, word changes and section references. RTWG deleted two paragraphs in section 7.1.2. These two sections were not needed in the Tariff 7.1.2(2)(b) and 7.1.2(4)(b).</td>
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<tr>
<td>Comment Status</td>
<td>MWG approved the MPRR as modified. The approved language is reflected in this recommendation report.</td>
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Comments Received

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<th>Comment Author</th>
<th>Debbie James</th>
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<tr>
<td>Date</td>
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<td>Comment Description</td>
<td>Clarification language was added by SPP staff. In Section 5, the word “monthly” was added to ARRs/LTCRs, because ARRs/LTCRs are a monthly product as well as annual and seasonal. A section reference was corrected in Section 5.6.3. Clarification language was added to the Tariff in Attachment AE Section 7.1.1. The proposed language is highlighted in yellow.</td>
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<tr>
<td>Comment Status</td>
<td>MWG approved the MPRR as modified. The approved language is reflected in this recommendation report.</td>
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Proposed Protocol Language Revision

1.0 Glossary

Auction Revenue Right (ARR)
As defined in Attachment AE of the Tariff.

A financial right, awarded during the annual ARR allocation process and/or the incremental monthly ARR allocation process, that entitles the holder to a share of the auction revenues generated in the applicable Transmission Congestion Rights (TCR) auction(s) and/or entitles the holder to self-covert the ARRs into TCRs.

ARR Nomination Cap

As defined in Attachment AE of the Tariff.

The maximum total amount of ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and/or the monthly incremental ARR allocation process.

Firm Point-to-Point ARR Nomination Cap (“FPTP ARR Nomination Cap”)

As defined in Attachment AE of the Tariff. The maximum total amount of FPTP Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and/or the monthly incremental ARR allocation process.

Firm Point-to-Point Candidate ARR (“FPTP Candidate ARR”)

As defined in Attachment AE of the Tariff. All or portion of the MW quantity of a confirmed Firm Point-To-Point Transmission Service Reservation (TSR), verified prior to the start of the annual ARR allocation process, that the holder of the TSR can nominate for conversion into an ARR in the annual ARR allocation process.

Firm Point-to-Point Candidate LTCR (“FPTP Candidate LTCR”)

As defined in Attachment AE of the Tariff.

GFA Firm Point-to-Point ARR Nomination Cap (“GFA FPTP ARR Nomination Cap”)

As defined in Attachment AE of the Tariff. The maximum total amount of GFA FPTP Candidate ARRs and GFA FPTP Incremental Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and/or the incremental monthly ARR allocation process.

GFA Firm Point-to-Point Candidate ARR (“GFA FPTP Candidate ARR”)

As defined in Attachment AE of the Tariff. All or a portion of the MW quantity of the transmission service component of a Grandfathered Agreement (GFA) providing service equivalent to Firm Point to Point Transmission Service, as defined in the SPP Tariff, verified prior to the start of the annual ARR allocation process, that the applicable
Eligible Entity can nominate for conversion into an ARR in the annual ARR allocation process.

**GFA Firm Point-to-Point Candidate LTCR (“GFA FPTP Candidate LTCR”)**

As defined in Attachment AE of the Tariff.

**GFA NITS ARR Nomination Cap**

As defined in Attachment AE of the Tariff. The maximum total amount of GFA NITS Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and the monthly Incremental ARR allocation process.

**GFA NITS Candidate ARR**

As defined in Attachment AE of the Tariff. All or a portion of the MW quantity of the transmission service component of a Grandfathered Agreement (GFA) providing service equivalent to Network Integration Transmission Service, as defined in the SPP Tariff, verified prior to the start of the annual ARR allocation process, that the applicable Eligible Entity can nominate for conversion into an ARR in the annual ARR allocation process.

**GFA NITS Candidate LTCR**

As defined in Attachment AE of the Tariff.

**Load Serving Entity (LSE)**

As defined in Attachment AE of the Tariff.

**Long-Term Congestion Right (LTCR)**

As defined in Attachment AE of the Tariff.

**NITS ARR Nomination Cap**

As defined in Attachment AE of the Tariff. The maximum total amount of NITS Candidate ARRs and NITS Incremental Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and/or the monthly Incremental ARR allocation process.

**NITS Candidate ARR**

As defined in Attachment AE of the Tariff. The MW quantity associated with firm NITS, that is verified prior to the start of the annual ARR allocation process, that the holder of the NITS can nominate for conversion into an ARR, subject to the NITS ARR...
Nomination Cap, in the annual ARR allocation process and the monthly ARR allocation process.\[MCRR6.9\]

NITS Candidate LTCR

As defined in Attachment AE of the Tariff.

Transmission Congestion Right (TCR)

As defined in Attachment AE of the Tariff A financial right that entitles the holder to a share of the congestion revenue collected in the Day-Ahead Market.

Transmission Congestion Rights Markets

As defined in Attachment AE of the Tariff The Auction Revenue Rights annual and monthly allocation processes and the annual and monthly Transmission Congestion Rights auctions.

3.2 Transmission Congestion Rights Markets

The structure of the TCR Markets includes annual nomination and allocation of Long-Term Congestion Rights (LTCRs) to Eligible Entities and annual and monthly nomination and allocation of Auction Revenue Rights (ARRs) to Eligible Entities followed by annual and monthly TCR Auctions. Eligible Entities for ARRs include Transmission Customers with firm SPP transmission service and entities with firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within or through the SPP Region that have identified such service during the annual LTCR/ARR verification process. Eligible Entities for LTCRs include Transmission Customers with qualifying firm SPP transmission service and entities with qualifying firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within and through the SPP Region that have identified such qualifying service during the annual LTCR/ARR verification process. Entities with firm non-SPP transmission service (GFA) must agree between the parties as to which party is eligible to nominate LTCRs and/or ARRs. Additionally, Eligible Entities may request NITS, GFA NITS, FPTP and/or GFA FPTP Incremental Candidate ARRs for firm transmission service confirmed following completion of the annual TCR auction.

Key features of the annual LTCR allocation process include:

1. Eligible Entities are awarded LTCRs that apply to the entire TCR year. Load Serving Entities (LSEs) are awarded LTCRs prior to consideration of LTCR awards for Eligible Entities that are not LSEs. Candidate LTCRs are only associated with eligible long-term firm transmission service with rollover rights-;
(2) All Candidate LTCRs are modeled in order to determine simultaneous feasibility of the Candidate LTCRs. LTCRs are only awarded up to the selected amount of simultaneously feasible Candidate LTCRs; 

(a) Candidate LTCRs are evaluated for simultaneous feasibility for flows in the prevailing direction only with no simultaneous consideration of LTCR flows in the opposite direction (i.e. counterflow is not considered in the feasibility analysis);

(b) 50% of the SPP transmission system capability is available for allocation;

(3) Awarded LTCRs are of the obligation type which means that the TCRs associated with the awarded LTCR could result in a payment or charge to the TCR holder in the Day-Ahead Market settlement of TCRs;

(a) Once awarded, the awarded LTCRs are guaranteed in subsequent years as long as the associated long-term firm SPP transmission service reservation remains in effect;

(b) Awarded LTCRs may be surrendered in subsequent years at the Market Participant's request;

(4) Awarded LTCRs are initially ARRs which will automatically be self-converted to TCRs in the annual ARR allocation process.

Key features of the annual ARR allocation process include:

(1) Eligible Entities nominate candidate ARRs separately for On-Peak and Off-Peak periods each month and season of the annual period in a three-round process;

(2) Nominated candidate ARRs are awarded up to the amount that is simultaneously feasible;

(3) Awarded ARRs are of the obligation type which means that the awarded ARR could result in a payment or charge to the ARR holder;

(3) 100% of the SPP transmission system capability is available for allocation;

(a) All awarded LTCRs are accounted for prior to assessing nominated ARR feasibility;

(b) Awarded ARRs are of the obligation type which means that the awarded ARR could result in a payment or charge to the ARR holder. Awarded LTCRs are converted to ARRs and included in the total ARR awards for settlement purposes;
Holders of ARRs receive positive or negative revenue resulting from the annual and monthly TCR auctions, including those ARRs that were self-converted to TCRs. ARRs associated with LTCRs are automatically self-converted into TCRs for settlement purposes. Positive auction revenue results when the sink Auction Clearing Price (ACP) is greater than the source ACP for a given ARR. Negative revenue results when the sink ACP is less than the source ACP, in other words, a counterflow ARR.

(a) For the annual TCR auction, the amount of ARRs eligible to receive auction revenues is equal to the greater of ARRs self-converted to TCRs or the amount of ARRs awarded multiplied by the following percentages: June – 100%; July through September, 90%; and Fall, Winter, Spring – 60%.

(b) For the monthly TCR auction for the months of July through September, the amount of ARRs eligible to receive auction revenues is equal to the amount of ARRs awarded in the incremental monthly ARR allocation process plus: the lesser of (i) 10% of the annual ARR award or (ii) the difference between the annual ARR award and the amount of self-converted TCRs in the annual TCR auction;

(c) For the monthly TCR auction for the months of October through May, the amount of ARRs eligible to receive auction revenues is equal to the amount of ARRs awarded in the incremental monthly ARR allocation process plus: the lesser of (i) 40% of the annual ARR award or (ii) the difference between the annual ARR award and the amount of self-converted TCRs in the annual TCR auction.

Key features of the annual TCR auction include:

(1) Any Market Participant that meets the applicable credit requirements may submit TCR Bids to purchase (for which the entity is the owner of record) and/or TCR Offers to sell separately for On-Peak and Off-Peak periods in the annual TCR auction for each month and season in the annual period;

(a) ARRs resulting from LTCRs are automatically self-converted into TCRs prior to auction clearing and are modeled as fixed injections/withdrawals. These TCRs may be offered for sale in the annual or monthly TCR auction process;

(1)(2) TCRs are of the obligation type which means that the awarded TCR could result in a payment or charge to the TCR holder in the DA Market settlement;

(2) The annual TCR auction is a single process for the month of June that makes 100% of the available SPP transmission system capability available, is a single round process for the months of July, August and September that makes 90% of the available SPP transmission
system capability available and is a single round process for the Fall, Winter and Spring seasons that makes 60% of the available SPP transmission system capability available;

(3) Market Participants who have TCR bids cleared in the annual TCR auction will be charged (or get paid in the case of a counter-flow TCR) based on the amount of TCR MWs cleared and the annual TCR auction clearing prices associated with the source and sink of the offered/purchased TCR;

(4) Market Participants who have TCR offers cleared in the annual TCR auction will be paid (or get charged in the case of a counter-flow TCR) based on the amount of TCR MWs cleared and the annual TCR auction clearing prices associated with the source and sink of the TCR sold;

(3) and

(4)(5) Market Participants holding ARRs not associated with LTCRs may self-convert their ARRs into TCRs for the applicable period subject to simultaneous feasibility. TCRs from self-converted ARRs, including TCRs self-converted from ARRs associated with LTCRs, are included as awarded TCRs.

Key features of the monthly incremental monthly ARR allocation include:

(1) Eligible Entities must submit a request to SPP specifying the NITS Incremental Candidate ARRs, GFA NITS Incremental Candidate ARRs, FPTP Incremental Candidate ARRs and/or GFA FPTP Incremental Candidate ARRs desired that are associated with the confirmed firm transmission service and the request must be submitted ten days prior to the start of the applicable monthly TCR auction process to be eligible to participate in the upcoming monthly TCR auction;

(2)(1) SPP verifies new firm transmission service reservations the request and performs a monthly incremental ARR allocation process beginning five days prior to the applicable monthly TCR auction process.

(a) Eligible Entities may nominate candidate ARRs from their verified NITS Incremental Candidate ARRs not to exceed the difference between their NITS ARR Nomination Cap and the those ARRs awarded in the annual ARR allocation process, from nominated NITS Candidate ARRs in the annual ARR allocation process;

(b) Eligible Entities may nominate candidate ARRs from their verified FPTP Incremental Candidate ARRs not to exceed the difference between their FPTP ARR Nomination Cap and the those ARRs awarded from nominated FPTP
Candidate ARRs in the annual ARR allocation processes;

(c) Eligible Entities may nominate candidate ARRs from their verified GFA NITS Incremental Candidate ARRs not to exceed the difference between their GFA NITS ARR Nomination Cap and those ARRs awarded from nominated GFA NITS Candidate ARRs in the annual ARR allocation process;

(d) Eligible Entities may nominate candidate ARRs from their verified GFA FPTP Incremental Candidate ARRs not to exceed the difference between their GFA FPTP ARR Nomination Cap and those ARRs awarded from nominated GFA FPTP Candidate ARRs in the annual ARR allocation process;

(e) Nominated candidate ARRs are awarded up to the amount that is simultaneously feasible;

(f) All TCRs previously awarded in the Annual TCR Auction Process and all remaining ARRs not accounted for in the Annual TCR Auction Process for the applicable month are modeled as fixed injections at the specified sources and fixed withdrawals at the specified sinks prior to assessing nominated incremental candidate ARR feasibility.

(3)(2) Awarded incremental ARRs are of the obligation type which means that the awarded incremental ARR could result in a payment or charge to the ARR holder; and

(4)(3) 100% of the SPP transmission system capability is available for allocation.

Key features of the monthly ARR-TCR auction include:

(1) The monthly TCR auction process allows any Market Participants that have met the applicable credit requirements to submit TCR Bids to purchase additional TCRs or TCR Offers to sell currently held TCRs in a single-round process for the months of July, August and September and in a two-round process for the months of October through May;

(2) 100% of the SPP transmission system capability is made available; and

(3) Market Participants may self-convert their remaining ARRs (including ARRs remaining from the annual TCR auction process and ARRs awarded in the incremental monthly ARR allocation process) into TCRs for the applicable period subject to simultaneous feasibility.

Exhibit 3-3 provides an overview of the TCR Markets structure.

Exhibit 3-3: Overview of TCR Markets Structure
The TCR Markets are operated in parallel with the timeline depicted in Exhibit 3-2 to ensure the Market Participants are able to obtain TCRs prior to DA Market operation. A representative timeline for the TCR Market processes is shown in Exhibit 3-4.
5. Transmission Congestion Rights Markets Process

The Energy and Operating Reserve Markets processes are described in detail in Section 4 and the TCR Markets processes are described in detail in Section 5.

The annual TCR Markets Process includes an annual LTCR allocation process, an annual and monthly ARR allocation process and annual and monthly TCR Auctions.

LTCRs are multi-year instruments, ARRrs are annual, monthly or seasonal instruments, and TCRs are monthly and seasonal financial instruments whose values are determined as part of the DA Market settlement based on the MW amount of the TCRs (including LTCRs converted to TCRs) and the DA Market differential of the Marginal Congestion Component of LMP between specified sinks and sources. TCRs are of the obligation type which means they can result in a credit or a charge. They provide a financial hedge against congestion costs in the DA Market as long as the MCC of the TCR sink Settlement Location is greater than the MCC of the TCR source Settlement Location. If the MCC at the TCR sink Settlement Location is less than the MCC of the TCR source Settlement Location, the TCR holder is charged (this type of TCR is commonly referred to as a “Counter-Flow TCR”).
Auction Revenue Rights (ARRs) are obtained by Eligible Entities during the annual ARR allocation process and/or incremental monthly ARR allocation process. LTCRs are automatically converted into ARRs and TCRs for modeling and settlement purposes. Holders of ARRs are entitled to receive the Annual and Monthly TCR Auction revenues associated with awarded TCR Bids. However, ARRs are of the obligation type which means they can result in the holder receiving a portion of the TCR auction revenues or contributing to the TCR auction revenues.

TCRs are obtained by Market Participants through the Annual and Monthly TCR Auctions. Optionally, ARR holders may convert their ARRs into TCRs in the Annual and Monthly TCR Auctions and either hold the TCRs or offer these TCRs for sale in the auctions. ARRs associated with LTCRs are automatically converted into TCRs which may be sold in the annual and Monthly TCR auctions.

The TCR Markets Process is subject to review by the Market Monitor, as needed.

There are 87 key steps associated with obtaining an LTCR or TCR and/or offering an awarded LTCR or TCR for sale.

1. Annual LTCR/ARR Verification Process;
2. Annual ARR Verification Process;
3. Annual LTCR Allocation Process;
4. Annual ARR Allocation Process;
5. Annual TCR Auction Process;
6. Monthly ARR Allocation Process;
7. Monthly TCR Auction Process;
8. Incremental ARR Allocation Process (if requested by Eligible Entity);
9. ARR Allocation and TCR Auction Settlements; and
10. TCR Secondary Markets.

Exhibit 5-1 provides an overall representative timeline related to the LTCR Allocation, ARR Allocation and TCR Auction processes and Exhibit 5-2 provides additional details related to auction timing and available transmission system capability of the TCR Auction processes.
Exhibit 5-1: LTCR/ARR Allocation and TCR Auction Processes Timeline
## Exhibit 5-2: TCR Auction Processes Summary

<table>
<thead>
<tr>
<th>Auction Month (System Capability %)</th>
<th>Auction Type</th>
<th>TCR Award Periods</th>
<th>TCR Products</th>
<th>Auction Rounds</th>
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<td>Jun (100)</td>
<td>Fall¹ (60)</td>
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<td></td>
<td>Jul (90)</td>
<td>Winter² (60)</td>
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<td></td>
</tr>
<tr>
<td>Jun</td>
<td>Monthly</td>
<td>Jul (100)</td>
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<td>2</td>
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<tr>
<td>(System Capability %)</td>
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<td></td>
<td></td>
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</tr>
<tr>
<td>Jul</td>
<td>Monthly</td>
<td>Aug (100)</td>
<td>On-Peak/Off-Peak</td>
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<tr>
<td>(System Capability %)</td>
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<tr>
<td>Aug</td>
<td>Monthly</td>
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<tr>
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<tr>
<td>Apr</td>
<td>Monthly</td>
<td>May (100)</td>
<td>On-Peak/Off-Peak</td>
<td>2</td>
<td>4</td>
</tr>
<tr>
<td>(System Capability %)</td>
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</tbody>
</table>

¹ October and November
² December, January, February, March
³ April and May
Key process and design assumptions of each of these seven-eight (7/8) key steps are described in the following sub-sections.

5.1 **Annual LTCR/ARR Verification Process**

Only Eligible Entities are eligible to nominate candidate LTCRs and/or ARRs as described under Sections 5.2 and 5.3. Eligible Entities for ARRs are Transmission Customers with firm SPP transmission service and entities with firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within or through the SPP Region that has been confirmed prior to the Annual ARR Allocation Process. Eligible Entities for LTCRs are Transmission Customers with qualifying firm SPP transmission service and entities with qualifying firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within or through the SPP Region that has been confirmed prior to the Annual LTCR Allocation Process. Eligible Entities must verify such services with SPP during the Annual LTCR/ARR Verification Process in order to be eligible to nominate candidate LTCRs and/or ARRs. All Eligible Entities must be a Market Participant and/or Asset Owner. The following rules apply to verification of transmission service for conversion to LTCRs and/or ARRs.

5.1.1 **Transmission Service Verification**

In order for Eligible Entities to obtain candidate LTCRs and/or ARRs, SPP must first verify existing transmission service entitlements, including transmission service entitlements which have been renewed in accordance with rollover rights since their initial term [MCRR1.15]. In order to qualify for candidate LTCRs, an Eligible Entity’s firm transmission service must contain rollover rights and must span the entire allocation year. In order to qualify for candidate ARRs in a particular month and/or season, an Eligible Entity’s transmission service must span the entire monthly or seasonal period within the applicable allocation year. SPP will verify each Eligible Entity’s existing transmission service entitlements as follows:

1. For Eligible Entities taking Network Integration Transmission Service (NITS) and/or Firm Point-To-Point Transmission Service (FPTP) under the SPP Tariff:
   
   a. SPP will obtain source, sink, and Reserved Capacity information from the SPP OASIS for each monthly and seasonal period for the applicable year in which the transmission service spans the entire period for ARR purposes and for the annual period for the applicable year for LTCR purposes;

   b. Eligible Entities taking NITS with rollover rights shall be considered an LSE for purposes of LTCR allocation.
(c) Eligible Entities taking FPTP service with rollover rights shall not be considered an LSE for that service unless the Eligible Entity provides an attestation to SPP confirming that the Eligible Entity is an LSE as defined in Attachment AE of the Tariff for such service;

(b)(d) For a TSR with a source inside the SPP Market that is not a specific Resource or Resource Hub, the load Settlement Location that most closely corresponds to the source on the reservation will be utilized as the source for candidate LTCRs and/or ARRs;

(e)(c) For a TSR with a source outside of the SPP Market, the Interface Settlement Location associated with the Balancing Authority of the source will be utilized as the source for candidate LTCRs and/or ARRs;

(f) For a TSR with a sink outside of the SPP Market, the Interface Settlement Location associated with the Balancing Authority of the sink will be utilized as the sink for candidate LTCRs and/or ARRs;

(d)(g) SPP will provide this information to each Eligible Entity for verification;

(e)(h) Eligible Entities will notify SPP within two (2) weeks following receipt of this information identifying and correcting inaccurate data. Otherwise, the SPP provided data will be considered verified.

(2) For Eligible Entities taking GFA service:

(a) If the transmission customer under the GFA desires to nominate ARRs associated with the GFA sources and sinks identified in the Grandfathered Agreement, the GFA Parties must register such GFA with SPP and provide SPP with sources, sinks and Reserved Capacity information. SPP will obtain source, sink and Reservation Capacity information from the GFA registration for each monthly and seasonal period for the applicable year in which the transmission service spans the entire period\[MCRR2.16\];

(b) Eligible Entities taking the equivalent of SPP NITS with rollover rights shall be considered an LSE for purposes of LTCR allocation;

(c) Eligible Entities taking the equivalent of SPP FPTP service with rollover rights shall not be considered an LSE for that service unless the Eligible Entity provides an attestation to SPP confirming that the Eligible Entity is an LSE as defined in Attachment AE of the Tariff for such service;

(b)(d) For a GFA with a source inside the SPP Market that is not a specific Resource or Resource Hub, the load Settlement Location that most closely corresponds to
the source on the reservation will be utilized as the source for candidate LTCRs and/or ARRs;

(c) For a GFA with a source outside of the SPP Market, the interface associated with the Balancing Authority of the source will be utilized as the source for candidate LTCRs and/or ARRs;

(f) For a GFA with a sink outside of the SPP Market, the interface associated with the Balancing Authority of the sink will be utilized as the sink for candidate LTCRs and/or ARRs;

In addition, the parties to the GFA must agree that the transmission customer under the GFA is eligible to nominate the LTCRs and/or ARRs associated with the GFA and both parties must confirm such with SPP. To the extent that the transmission service specified in the GFA is identified as the equivalent of SPP NITS, the transmission customer under the GFA must provide the historical non-coincident peak loads (“GFA Annual Peak Load”) being served under the GFA for the previous three years since February 1, 2007.

5.1.2 Candidate LTCRs/ARRs

Following verification of Eligible Entity transmission service, candidate LTCRs and/or ARRs associated with such transmission service are assigned as follows:

(1) For each Eligible Entity with NITS, the Eligible Entity’s NITS Candidate LTCRs and/or ARRs from a specific source is then equal to the source Reserved Capacity.

(a) An Eligible Entity may nominate select NITS Candidate LTCRs and/or ARRs, as described under Section 5.2.65.2.1 from a specific source to one or more sinks up to the amount of its available NITS Candidate ARRs and LTCRs associated with the source subject to the total nomination limit described under Section 5.1.3.

(b) An Eligible Entity may nominate NITS Candidate ARRs, as described under Section 5.3.1 from a specific source to one or more sinks up to the amount of its NITS Candidate ARRs associated with the source subject to the total nomination limit described under Section 5.1.3.

(2) For each Eligible Entity with FPTP service, the Eligible Entity’s FPTP Candidate LTCRs and/or ARRs for a specific source and sink is equal to the Reserved Capacity associated with that source and sink.

(a) An Eligible Entity may nominate select FPTP Candidate ARRs and LTCRs, as described under Section 5.2.65.2.1, for this specific source and sink up to the
amount of its available FPTP Candidate ARRLTCRs subject to the total nomination limit described under Section 5.1.3.

(b) An Eligible Entity may nominate FPTP Candidate ARRs, as described under Section 5.3.1, for this specific source and sink up to the amount of its FPTP Candidate ARRs subject to the total nomination limit described under Section 5.1.3.

(3) For each Eligible Entity with equivalent NITS GFA service, the Eligible Entity’s GFA NITS Candidate LTCRs and/or ARRs from a specific source is equal to the source Reserved Capacity.

(a) An Eligible Entity may nominate select GFA NITS Candidate ARRs, as described under Section 5.2.6, from a specific source to one or more sinks up to the amount of its available GFA NITS Candidate ARRs subject to the total nomination limit described under Section 5.1.3.

(b) An Eligible Entity may nominate GFA NITS Candidate ARRs, as described under Section 5.3.1, for this specific source and sink up to the amount of its GFA NITS Candidate ARRs subject to the total nomination limit described under Section 5.1.3.

(4) For each Eligible Entity with equivalent FPTP GFA service, the Eligible Entity’s GFA FPTP Candidate LTCRs and/or ARRs for a specific source and sink is equal to the Reserved Capacity associated with that source and sink.

(a) An Eligible Entity may nominate select GFA FPTP Candidate ARRLTCRs, as described under Section 5.2.6, for this specific source and sink up to the amount of its available GFA FPTP Candidate ARRLTCRs subject to the total nomination limit described under Section 5.1.3.

(b) An Eligible Entity may nominate GFA FPTP Candidate ARRs, as described under Section 5.3.1, for this specific source and sink up to the amount of its GFA FPTP Candidate ARRs subject to the total nomination limit described under Section 5.1.3.

5.1.3 ARR Nomination Cap

An Eligible Entity’s ARR Nomination Cap will be as follows:

(1) For NITS Transmission Customers, the NITS ARR Nomination Cap is equal to the minimum of a) the sum of NITS Candidate ARRs and NITS Candidate LTCRs as calculated under Section 5.1.2 and NITS Incremental Candidate ARRs as calculated...
under Section 5.5.2 [MCRR.6.19] or b) **one hundred and three (103%) of the average of that customer’s three most recent annual peak Network Loads.** This value may will be adjusted by SPP [MCRR.2.20] as required to account for wholesale load shifts between Transmission Customers. In addition, NITS Candidate LTCRs and awarded NITS Candidate LTCRs associated with wholesale load shifts shall be transferred by SPP as applicable;

(2) For FPTP Transmission Customers, the FPTP ARR Nomination Cap is equal to the sum of FPTP Candidate ARRs and **FPTP Candidate LTCRs** as calculated under Section 5.1.2 and **FPTP Incremental Candidate ARRs** as calculated under Section 5.5.2 [MCRR.6.21];

(3) For GFA customers taking the equivalent of SPP NITS, the GFA NITS ARR Nomination Cap is equal to the minimum of a) the sum of GFA NITS Candidate ARRs and **GFA NITS Candidate LTCRs** as calculated under Section 5.1.2 and **GFA NITS Incremental Candidate ARRs** as calculated under Section 5.5.2 [MCRR.6.22] or b) **one hundred and three percent (103%) of the average of that GFA customer’s three most recent annual peak Network Loads** since February 1, 2007 [MCRR.2.23];

(4) For GFA customers taking the equivalent of SPP FPTP, the GFA FPTP ARR Nomination Cap is equal to the sum of GFA FPTP Candidate ARRs and **GFA FPTP Candidate LTCRs** as calculated under Section 5.1.2 and **GFA FPTP Incremental Candidate ARRs** as calculated under Section 5.5.2 [MCRR.6.24];

(5) An Eligible Entity’s ARR Nomination Cap is equal the sum of its NITS ARR Nomination Cap, FPTP ARR Nomination Cap, GFA NITS ARR Nomination Cap and GFA FPTP ARR Nomination Cap.

### 5.2 Annual LTCR Allocation Process

The Annual LTCR Allocation Process addresses how candidate LTCRs verified in the Annual LTCR/ARR Verification Process may be selected and awarded as LTCRs. The annual allocation process determines the portion of the candidate LTCRs that are simultaneously feasible and available to each Eligible Entity to select. **50% of the SPP Residual Transmission System Capability, as defined under Section 5.2.2(2), is made available during the Annual LTCR Allocation Process.** Candidate LTCRs are evaluated on an annual basis in a two-step process. The first step evaluates LSE candidate LTCRs to determine LSE available LTCRs. The second step evaluates non-LSE candidate LTCRs associates. No later than five (5) Business Days prior to the start of the Annual LTCR Allocation Process, SPP will post the transmission system network topology data for the annual model, along with corresponding Parallel Flow...
assumptions, that SPP will use in the upcoming allocation process for use by Eligible Entities in
developing their available candidate LTCR selection strategies. The following rules apply to the
annual allocation of LTCRs.

5.2.1 LTCR Surrender

Eligible Entities may surrender previously awarded LTCRs in 0.1 MW increments. Prior to
annual LTCR allocation, Eligible Entities submit the following information:

1. Source (valid candidate LTCR source Settlement Location);
2. Sink (valid candidate LTCR sink Settlement Location);
3. Surrendered LTCR MW (cannot exceed previously awarded LTCR).

5.2.2 Candidate LTCR Simultaneous Feasibility for LSEs

A simultaneous feasibility test (SFT) is performed to determine the feasibility of all NITS
Candidate LTCRs, FPTP Candidate LTCRs, GFA NITS Candidate LTCRs and GFA FPTP
Candidate LTCRs identified as described under Section 5.1.2 for all LSEs. All LSE candidate
LTCRs are modeled as a generation injection at the source and a corresponding load withdrawal
at the sink. The feasibility analysis assures the modeling of the LSE candidate LTCRs does not
violate any normal transmission line thermal ratings under normal system conditions and does
not violate short-term Emergency transmission line thermal ratings following a single
contingency (N-1 contingency analysis). The SFT is performed consistent with the transmission
system loading analysis that is performed as part the Security Constrained Economic Dispatch
process in the DA Market and includes consideration of the impact of Parallel Flow.

1. The SPP Transmission System topology used in the SFT is the most up-to-date
Network Model.

(a) For withdrawals at Settlement Locations containing more than one PNode, SPP
will distribute the Settlement Location withdrawal down to the PNode level using
load distribution percentages from the peak hour of the corresponding most recent
historical period (i.e. prior year peak). These load distribution percentages are
calculated using the methodology described under Section 4.1.2.1.6.

(b) For injections at Market Hubs, SPP will distribute the hub injection down to the
PNode level on a pro-rata basis using the weighting factors defined when the hub
is created.

2. Prior to assessing simultaneous feasibility, the normal and emergency ratings of all
flowgates and monitored transmission system elements are adjusted as follows to arrive
at an SPP Residual Transmission System Capability:
(a) Adjusted Monitored Transmission Line Rating (normal and Emergency) =
(Monitored Transmission Line Rating [normal and Emergency – Parallel Flow impact])

(b) Adjusted Flowgate Rating (normal and Emergency) =
(Flowgate Rating – Parallel Flow impact)

(3) The feasibility analysis evaluates the candidate LTCR feasibility by evaluating line flows against path limits in a single direction only without simultaneous consideration of line flows created by candidate LTCRs in the opposite direction (i.e. counter-flow will not act to increase the feasibility of candidate LTCRs).

(4) The feasibility analysis uses an iterative process to ensure that previously awarded LTCRs that have not been surrendered as indicated pursuant to Section 5.2.1 continue to be available.

(a) For the initial feasibility analysis, no previously awarded LSE LTCRs or surrendered LSE LTCRs are modeled. Only candidate LSE LTCRs are modeled.

(b) Previously awarded LTCRs associated with qualified transmission service as verified under Section 5.1.1 and which were not surrendered, associated with non-LSEs are modeled as fixed injections and withdrawals. To the extent that these fixed injections and withdrawals are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to assessing LSE LTCR availability. SPP will report back to the MWG when transmission line ratings had to be adjusted to ensure feasibility.

(c) If the results of the initial feasibility analysis show that the amount of LSE LTCRs feasible on specific paths are less than those LSE LTCRs previously awarded on those paths, net of any surrendered LSE LTCRs, the feasibility analysis is rerun with all previously awarded LSE LTCRs, net of any surrendered LSE LTCRs, on such paths modeled as fixed injections/withdrawals and all candidate LSE LTCRs on all other paths are modeled as in (a) above. To the extent that these fixed injections and withdrawals are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility. SPP will report back to the MWG when transmission line ratings had to be adjusted to ensure feasibility.

5.2.3 Annual LTCRs Available for LSEs

If all of the candidate LSE LTCRs are confirmed feasible, all candidate LSE LTCRs are available. If candidate LSE LTCRs are not feasible, the amount of candidate LSE LTCRs
available will be reduced using a weighted least squares method. The weighted least squares method minimizes the least squares deviation from the candidate LSE LTCR MW weighted by the reciprocal of the candidates resulting in a higher percentage LSE LTCR reduction for those candidates having the greatest impact on the constraints. LSE LTCR reductions associated with candidates that have an equal impact on the constraints are reduced by the same percentage.

5.2.4 Candidate LTCR Simultaneous Feasibility for Non-LSEs

A simultaneous feasibility test (SFT) is performed to determine the feasibility of all NITS Candidate LTCRs, FPTP Candidate LTCRs, GFA NITS Candidate LTCRs and GFA FPTP Candidate LTCRs identified as described under Section 5.1.2 for all non-LSEs. All non-LSE candidate LTCRs are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. The feasibility analysis assures the modeling of the non-LSE candidate LTCRs does not violate any normal transmission line thermal ratings under normal system conditions and does not violate short-term Emergency transmission line thermal ratings following a single contingency (N-1 contingency analysis). The SFT is performed consistent with the transmission system loading analysis that is performed as part of the Security Constrained Economic Dispatch process in the DA Market and includes consideration of the impact of Parallel Flow.

(1) The SPP Transmission System topology used in the SFT is the most up-to-date Network Model.

(a) For withdrawals at Settlement Locations containing more than one PNode, SPP will distribute the Settlement Location withdrawal down to the PNode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. prior year peak). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.6.

(b) For injections at Market Hubs, SPP will distribute the hub injection down to the PNode level on a pro-rata basis using the weighting factors defined when the hub is created. [MPRR90.26]

(2) Prior to assessing simultaneous feasibility, the normal and emergency ratings of all flowgates and monitored transmission system elements are adjusted as follows to arrive at an SPP Residual Transmission System Capability:

(c) Adjusted Monitored Transmission Line Rating (normal and Emergency) =

\[
\text{(Monitored Transmission Line Rating (normal and Emergency – Parallel Flow impact))}
\]

(d) Adjusted Flowgate Rating (normal and Emergency) =
(Flowgate Rating – Parallel Flow impact)

(3) The feasibility analysis evaluates the candidate LTCR feasibility by evaluating line flows against path limits in a single direction only without simultaneous consideration of line flows created by candidate LTCRs in the opposite direction (i.e., counter-flow will not act to increase the feasibility of candidate LTCRs).

(4) The feasibility analysis uses an iterative process to ensure that previously awarded LTCRs that have not been surrendered as indicated pursuant to Section 5.2.1 continue to be available.

(a) For the initial feasibility analysis, no previously awarded non-LSE LTCRs or surrendered non-LSE LTCRs are modeled. Only candidate non-LSE LTCRs are modeled.

(b) Available LSE LTCRs as calculated under Section 5.2.3 are modeled as fixed injections and withdrawals.

(c) If the results of the initial feasibility analysis show that the amount of non-LSE LTCRs feasible on specific paths are less than those non-LSE LTCRs previously awarded on those paths associated with qualified transmission service as verified under Section 5.1.1 and which were not surrendered, net of any surrendered non-LSE LTCRs, the feasibility analysis is rerun with all previously awarded non-LSE LTCRs, net of any surrendered non-LSE LTCRs, on such paths modeled as fixed injections/withdrawals and all candidate non-LSE LTCRs on all other paths are modeled as in (a) above. To the extent that these fixed injections and withdrawals are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to LSE LTCR availability. SPP will report back to the MWG when transmission line ratings had to be adjusted to ensure feasibility.

5.2.5 Annual LTCRs Available for Non-LSEs

If all of the candidate non-LSE LTCRs are confirmed feasible, all candidate non-LSE LTCRs are available. If candidate non-LSE LTCRs are not feasible, the amount of candidate non-LSE LTCRs available will be reduced using a weighted least squares method. The weighted least squares method minimizes the least squares deviation from the candidate non-LSE LTCR MW weighted by the reciprocal of the candidates resulting in a higher percentage non-LSE LTCR reduction for those candidates having the greatest impact on the constraints. Non-LSE LTCR reductions associated with candidates that have an equal impact on the constraints are reduced by the same percentage.
The Transmission Provider will post the amounts of candidate non-LSE LTCRs which are available for the non-LSE Eligible Entity's selection.

5.2.6 LTCR Selections and Awards

1. All previously awarded LTCRs associated with qualified transmission service as verified under Section 5.1.1 and which were not surrendered, as described under Section 5.2.1, are automatically awarded as LTCRs for the current allocation year.

2. Additional available candidate LTCRs are selected and awarded in a single-round process. Eligible Entities may select:

   (a) Available LTCRs from their NITS Candidate LTCRs as described under Section 5.2.3 or Section 5.2.5, less any previously awarded LTCRs plus any surrendered LTCRs associated with NITS Candidate LTCRs;

   (b) Available LTCRs from their FPTP Candidate LTCRs as described under Section 5.2.3 or Section 5.2.5, less any previously awarded LTCRs plus any surrendered LTCRs associated with FPTP Candidate LTCRs;

   (c) Available LTCRs from their GFA NITS Candidate LTCRs as described under Section 5.2.3 or Section 5.2.5, less any previously awarded LTCRs plus any surrendered LTCRs associated with GFA NITS Candidate LTCRs;

   (d) Available LTCRs from their GFA FPTP Candidate LTCRs as described under Section 5.2.3 or Section 5.2.5, less any previously awarded LTCRs plus any surrendered LTCRs associated with GFA FPTP Candidate LTCRs;

3. Eligible Entities must submit the following information in order to select LTCRs:

   (a) Source (valid candidate LTCR source Settlement Location);

   (b) Sink (valid candidate LTCR sink Settlement Location);

   (c) Selected LTCR MW (total LTCR MW nominated from a source Settlement Location cannot exceed the source candidate available LTCR MW as previously determined under Section 5.2.3 or Section 5.2.5, less previously awarded LTCRs plus surrendered LTCRs);

4. All selected LTCRs are automatically awarded.

5.3 Annual ARR Allocation Process

The Annual ARR Allocation Process addresses how candidate ARRs verified in the Annual LTCR/ARR Verification Process may be nominated and converted to ARRs. Eligible Entities
may nominate the candidate ARRs that they wish to receive up to their **ARR-Nomination Caps** less any LTCRs awarded plus any LTCRs surrendered.  **Any candidate LTCRs not awarded in the Annual LTCR Allocation Process and surrendered LTCRs become candidate ARRs.** The annual allocation process determines the portion of the nominated candidate ARRs that are simultaneously feasible to allocate to each Eligible Entity.  100% of the SPP Residual Transmission System Capability, as defined under Section 5.2.2(2), is made available during the Annual ARR Allocation Process.  Candidate ARRs are nominated on a monthly and seasonal basis in a three-round process.  No later than five (5) Business Days prior the start of the Annual ARR Allocation Process, SPP will post the transmission system network topology data for each of the monthly and seasonal on-peak and off-peak models, along with corresponding Parallel Flow and transmission line outage assumptions, that SPP will use in the upcoming allocation process for use by Eligible Entities in developing their candidate ARR nomination strategies. Exhibit 5-3 provides a representative timeline of the three-round annual ARR allocation process.
The following rules apply to the annual allocation of ARRs.

### 5.3.1 ARR Nominations

For each month and season included in the Annual ARR Allocation Process period, Eligible Entities may nominate candidate ARRs in 0.1 MW increments for specific source to sink pairs that total up to their ARR Nomination Caps as calculated under Section 5.1.3. Nominations occur separately for On-Peak and Off-Peak periods (8 separate transmission system models created representing each month in an annual allocation period and on-peak and off-peak periods within each month and 6 separate transmission system models created representing each season in an annual allocation period and on-peak and off-peak periods within each season). Prior to each ARR nomination round, Eligible Entities submit the following information:

1. Source (valid candidate ARR source Settlement Location for Rounds 1 and 2, any source Settlement Location for Round 3);
2. Sink (valid candidate ARR sink Settlement Location for Rounds 1 and 2, any sink Settlement Location for Round 3);
3. Class (on-peak or off-peak);
Period (month or season);  
Nominated ARR MW.

(a) In Round 1 and Round 2, the total candidate ARR MW nominated from a source Settlement Location cannot exceed the source candidate ARRs less awarded source LTCRs.

(b) In Round 3, any source to sink path may be nominated, subject to the limitation described under Section 5.23.2(3).

5.3.2 ARR Allocation

ARRs are allocated in a three-round process as follows:

(1) In Round 1, Eligible Entities may nominate:

(a) ARRs from their NITS Candidate ARRs that total to no more than the greater of (i) zero or (ii) 50% of their NITS ARR Nomination Cap less the sum of their awarded LTCRs from their NITS Candidate LTCRs;

(b) ARRs from their GFA NITS Candidate ARRs that total to no more than the greater of (i) zero or (ii) 50% of their GFA NITS ARR Nomination Cap less the sum of their awarded LTCRs from their GFA NITS Candidate LTCRs;

(c) ARRs from their FPTP Candidate ARRs that total to no more than the greater of (i) zero or (ii) 50% of their FPTP ARR Nomination Cap less the sum of their awarded LTCRs from their FPTP Candidate LTCRs; and

(d) ARRs from their GFA FPTP Candidate ARRs that total to no more than the greater of (i) zero or (ii) 50% of their GFA FPTP ARR Nomination Cap less the sum of their awarded LTCRs from their GFA FPTP Candidate LTCRs.

(2) In Round 2, Eligible Entities may nominate:

(a) ARRs from their NITS Candidate ARRs that total to no more than the greater of (i) zero or (ii) 100% of their NITS ARR Nomination Cap less any nominated NITS Candidate ARRs awarded in Round 1 and less the sum of their awarded LTCRs from their NITS Candidate LTCRs;

(b) ARRs from their GFA NITS Candidate ARRs that total to no more than the greater of (i) zero or (ii) 100% of their GFA NITS ARR Nomination Cap less any nominated GFA NITS Candidate ARRs awarded in Round 1 and less the sum of their awarded LTCRs from their GFA NITS Candidate LTCRs;
(c) ARRs from their FPTP Candidate ARRs that total to no more than the greater of 
(i) zero or (ii) 100% of their FPTP ARR Nomination Cap less any nominated 
FPTP Candidate ARRs awarded in Round 1 and less the sum of their awarded 
LTCRs from their FPTP Candidate LTCRs; and

(d) ARRs from their GFA FPTP Candidate ARRs that total to no more than the 
greater of (i) zero or (ii) 100% of their GFA FPTP ARR Nomination Cap less any 
nominated GFA FPTP Candidate ARRs awarded in Round 1 and less the sum of 
their awarded LTCRs from their GFA FPTP Candidate LTCRs.

(3) In Round 3, Eligible Entities may nominate ARRs from any source to sink that total 
to no more than the greater of (i) zero or (ii) 100% of their ARR Nomination Cap less any 
nominated candidate ARR amounts awarded in Rounds 1 and 2 and less the sum of their 
awarded LTCRs. In Round 3, a Market Participant is limited to a maximum combined 
submittal of 2000 ARR Nominations per product for each Asset Owner it represents.

Exhibit 5-4 provides an example of valid Round 1 NITS Candidate ARR nominations for a 
NITS Transmission Customer with a three year average historical annual peak load of 1942 
MW, total Candidate ARRs of 2400 MWs and 300 MWs of LTCRs.

**Exhibit 5-4: Candidate ARR Nomination for NITS**

<table>
<thead>
<tr>
<th>NITS ARR Nomination Cap</th>
<th>Round 1 ARR Nomination Limit</th>
<th>NITS Candidate ARR MW</th>
<th>Source</th>
<th>Sink</th>
<th>LTCR</th>
<th>Nominated NITS Candidate ARR MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000 MW(^4)</td>
<td>1000 MW(^5)</td>
<td>1200</td>
<td>G1</td>
<td>L1</td>
<td>200</td>
<td>6800</td>
</tr>
<tr>
<td></td>
<td></td>
<td>800</td>
<td>G2</td>
<td>L1</td>
<td>100</td>
<td>1200</td>
</tr>
<tr>
<td></td>
<td></td>
<td>400</td>
<td>G3</td>
<td>L1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>2400</td>
<td></td>
<td></td>
<td>300</td>
<td>10700</td>
</tr>
</tbody>
</table>

**5.3.3 Simultaneous Feasibility**

A simultaneous Feasibility Test (SFT) analysis is performed in each round to ensure that the 
nominated candidate ARRs, with nominated candidate ARR MW modeled as generation 
injection at the source and a corresponding load withdrawal at the sink, do not violate any

\(^4\) Lesser of (1.03 * 1942 MW) or 2400 MW

\(^5\) 50% of NITS ARR Nomination Cap
normal transmission line thermal ratings under normal system conditions and do not violate short-term Emergency transmission line thermal ratings following a single contingency (N-1 contingency analysis). The SFT is performed consistent with the transmission system loading analysis that is performed as part the Security Constrained Economic Dispatch process in the DA Market and includes consideration of the impact of Parallel Flow. 100% of the SPP Residual Transmission System Capability, as defined under Section 5.2.2(2), is made available during the analysis.

(1) The SPP Transmission System topology used in the SFT is the most up-to-date Network Model for all allocation periods, updated for forecasted transmission topology changes including planned maintenance outages.

(a) For withdrawals at Settlement Locations containing more than one PNode, SPP will distribute the Settlement Location withdrawal down to the PNode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. June, July, August, September, Fall, Winter and Spring). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.6.

(b) For injections at Market Hubs, SPP will distribute the hub injection down to the PNode level on a pro-rata basis using the weighting factors defined when the hub is created.

(2) All previously awarded LTCRs that have not been surrendered are modeled as fixed injections/withdrawals.

(2) Prior to assessing simultaneous feasibility, the normal and emergency ratings of all flowgates and monitored transmission system elements are adjusted as follows to arrive at an SPP Residual Transmission System Capability:

(3) Adjusted Monitored Transmission Line Rating (normal and Emergency) =

(Monitored Transmission Line Rating (normal and Emergency) – Parallel Flow impact)

(a) Adjusted Flowgate Rating (normal and Emergency) =

(Flowgate Rating – Parallel Flow impact)

Every six (6) months for the first two (2) years after implementation of the Integrated Marketplace, SPP will analyze the net funding of TCRs through the Day-Ahead Market and report to the MWG. In the event the cumulative funding is at or below 90% or above 100%, MWG may approve an additional adjustment of all subsequent monthly auctions and the month
of June in the annual auction of the normal and emergency ratings of all flowgates and monitored transmission system elements in (2) above.

5.3.4 Annual ARR Awards

All LTCR awards are automatically converted to ARR awards which are then automatically self-converted to TCRs in the Annual TCR Auction. If all of the nominated candidate ARRs are confirmed feasible, all nominated candidate ARRs are awarded. If the nominated candidate ARRs are not feasible, the amount of nominated candidate ARRs to be awarded will be reduced using a weighted least squares method. The weighted least squares method minimizes the least squares deviation from the nominated candidate ARR MW weighted by the reciprocal of the nominations resulting in a higher percentage ARR reduction for those nominations having the greatest impact on the constraints. ARR reductions associated with nominations that have an equal impact on the constraints are reduced by the same percentage.

5.4 Annual TCR Auction

The Annual TCR Auction Process is the mechanism through which Market Participants may obtain annual TCRs through submission of TCR Bids to purchase TCRs and/or through direct conversion of ARRs into TCRs through self-conversion. Various percentages of the SPP Residual Transmission System Capability, as calculated under Section 5.2.2(2), is made available during the Annual TCR Auction Process as shown in Exhibit 5-2. TCRs in the annual auction are auctioned in a single round process for all months and seasons. TCRs that originated as LTCRs may be sold as TCRs during this single round process. If there are any changes to the transmission system topology or Parallel Flow data after the conclusion of Annual ARR Allocation Process, SPP will post such changes no later than three (3) Business Days prior to the start of the Annual TCR Auction Process. Exhibit 5-5 provides a representative timeline of the two-round and single round annual TCR auction process.
The following rules apply to the Annual TCR Auction:

5.4.1 **TCR Offer and Bid** Submittal

1. Any Market Participant that has satisfied the applicable credit requirements may participate in the Annual TCR Auction;

2. Market Participants holding ARRs may elect to self-convert all or a portion of those ARRs into TCRs with the same source and sink by specifying the Self-Convert option as part of the TCR Bid submittal. **All ARRs associated with LTCRs are automatically converted to TCRs prior to the start of the Annual TCR Auction and these TCRs will be considered Self-Converted ARRs for the purposes of settlement. These TCRs can then be offered for sale in the Annual TCR Auction.**

3. For each month and season included in the Annual TCR Auction period, Market Participants may submit TCR Bids and TCR Offers in 0.1 MW increments separately, for On-Peak and Off-Peak periods (8 separate transmission system models created representing each month in an annual auction period and on-peak and off-peak periods within each month and 6 separate transmission system models created representing each season in an annual auction period and on-peak and off-peak periods within each season).

The following information is submitted for a TCR Bid or a TCR Offer:

- **TCR Offer and Bid** Submittal:
  - Market Participant identity
  - TCR type (TCR Offer or TCR Bid)
  - Transmission system model
  - On-Peak and Off-Peak periods
  - Bid or Offer price
  - Bid or Offer quantity
  - Source and sink location
  - Credit requirements
(a) Source (any valid Settlement Location);
(b) Sink (any valid Settlement Location);
(c) Class (on-peak or off-peak);
(d) Period (month or season);
(e) Type (Bid, or Self-Convert, Offer);
(f) TCR MW;
(g) TCR Price ($/MW);

(i) TCR Bids and Offers cannot exceed $100,000/MW-Month;

(ii) TCR Bids and Offers cannot be less than ($100,000/MW-Month).

(4) For each TCR Round, a Market Participant is limited to a maximum combined submittal of 2000 TCR Bids and/or TCR Offers and/or TCR Offers for each Asset Owner it represents.

5.4.2 Annual TCR Auction Process

TCRs are auctioned in a single-round process for each month and season using the SPP Residual Transmission System Capability as defined under Section 5.2.3 as follows:

(1) 100% of the SPP Residual Transmission System Capability is made available for the month of June, 90% of the SPP Residual Transmission System Capability is made available for the July-September period and 60% of the SPP Residual Transmission System Capability is made available for the Fall, Winter and Spring seasons;

(a) TCR Bids of the Self-Convert Type may be submitted for each source to sink pair that the Market Participant desires to convert the associated ARRs into TCRs. The Self-Convert Type option will convert ARRs associated with the specified source to sink pair into the TCR MW specified subject to simultaneous feasibility.

(b) Only Eligible Entities holding ARRs may submit a Self-Convert TCR Bid.

(c) The Self-Convert TCR Bid must specify the same source and sink as the associated ARR and the TCR MW must be less than or equal to the associated /ARR MW.
5.4.3 Annual TCR Auction Clearing and Simultaneous Feasibility

The Auction is performed using a Linear Program algorithm with an objective function to maximize the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible.

1. The SFT is performed as described under Section 5.3.3 with TCR Bid MW modeled as an injection at the source and a corresponding withdrawal at the sink and TCR Offer MW modeled as an injection at the sink and a withdrawal at the source.

2. The SPP Transmission System topology and Parallel Flow assumptions used in the SFT are normally the same as used in the Annual ARR Allocation process. However, unforeseen events that drastically impact transmission system topology that occur following the ARR Allocation but prior to the Annual TCR Auction will be accounted for in the models for the Annual TCR Auctions.

5.4.4 Annual TCR Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid prices such that the total TCR auction value is maximized. TCRs associated with LTCRs result from ARRs that automatically become Self-Converted TCRs for settlement purposes. Self-Converted TCRs not associated with LTCRs are evaluated simultaneously with submitted TCR Bids and Offers. In the event there is a tie during the SFT, the competing bids and offers will be awarded pro rata based on their impact(s) to the constraint(s). Auction Clearing Prices (ACP) are calculated for each Settlement Location using the formula for the Marginal Congestion Component as described under Section 4.5.4.1.2 \( MCC_i = - \left( \sum_{k=1}^{K} \text{Sens}_{ik} * \text{SP}_k \right) \).

For example, if we assume a 3 bus system (Bus A, B and C) and Bus A is the Reference Bus, we can calculate the ACP at Bus B as follows:
Transmission Line B-C is at its limit with a Shadow Price = $40/MW
Transmission Line A-C is at its limit with a Shadow Price = $30/MW
Transmission Line A-B is not at its limit (Shadow Price = $0/MW)
Shift Factor for Bus B on Line B-C is 30%
Shift Factor for Bus B on Line A-C is -80%

Then ACP at Bus B is equal to - \[($40/MW \times 0.3) + ($30/MW \times (-0.8))\] = $12/MW

A similar calculation is performed for Bus C based on Bus C Shift Factors. The ACP at Bus A is equal to zero since Bus A is the Reference Bus.

5.5 Incremental Monthly ARR Allocation Process

Eligible Entities with remaining candidate ARR capacities from the Annual ARR Allocation Process along with firm transmission service that has been confirmed following completion of the Annual TCR Auction Process and prior to the next Annual ARR Verification Process or with firm transmission service confirmed the Annual ARR Verification Process that includes a partial season or transmission service that has been confirmed following completion of the Annual ARR Allocation Process period for which the firm transmission service applies that was not eligible for conversion into ARRs during the Annual ARR Allocation Process are eligible to nominate candidate ARRs associated with such services. Incremental Candidate ARRs may be nominated for each remaining month in the current Annual ARR Allocation Process period for which the firm transmission service term extends beyond the current Annual ARR Allocation Process period, such remaining service will be included in the next Annual ARR Verification Process. Eligible Entities must submit a request to SPP for conversion of such services into ARRs in order to be eligible to nominate incremental candidate ARRs.

5.5.1 Incremental Monthly ARR Transmission Service Verification

In order for Eligible Entities to obtain incremental candidate ARRs, SPP must first verify existing transmission service entitlements. In order to qualify for incremental candidate ARRs in a particular month, an Eligible Entity’s transmission service must span the entire month within the applicable year. SPP will verify Eligible Entity existing transmission service entitlements as follows:

1. An Eligible Entity must submit a request to SPP no later than ten days prior to the start of the applicable TCR Monthly Auction Process specifying its desire to obtain incremental candidate ARRs associated with the approved and confirmed Transmission Service
The request must contain source, sink and Reserved Capacity information.

(2)(1) SPP will verify that the source, sink and Reserved Capacity information submitted has been accurately reflected on the SPP OASIS for the applicable month; and

(3)(2) SPP will notify the Eligible Entity for verification no later than two days following receipt of the request if the OASIS data does not match the data submitted in the request. Otherwise the Eligible Entity should consider the request approved.

(4) Eligible Entities will notify the Transmission Provider within six (6) days following receipt of this information, identifying and correcting inaccurate data on the OASIS. Otherwise, the Transmission Provider provided data will be considered verified. If SPP notifies the Eligible Entity as described in (3) above that it cannot verify the Eligible Entity’s request, the Eligible Entity must either correct the OASIS data or resubmit its request with corrected data that matches the OASIS data no later than six days prior to the start of the applicable TCR Monthly Auction Process.
5.5.2 Incremental Candidate ARRs

Following verification of Eligible Entity transmission service, incremental candidate ARRs associated with such transmission service are assigned as follows:

i. For each Eligible Entity with NITS confirmed and verified following completion of the Annual TCR Auction Process, the Eligible Entity’s NITS Incremental Candidate ARRs from a specific source is then equal to the source Reserved Capacity. An Eligible Entity may nominate NITS Incremental Candidate ARRs, as described under Section 5.5.3 from a specific source to one or more sinks up to the amount of its NITS Incremental Candidate ARRs associated with the source subject to its NITS ARR Nomination Cap described under Section 5.1.3;

(3) For each Eligible Entity with equivalent NITS GFA service confirmed and verified following completion of the Annual TCR Auction Process, the Eligible Entity’s GFA NITS Incremental Candidate ARRs from a specific source is equal to the source Reserved Capacity. An Eligible Entity may nominate GFA NITS Incremental Candidate ARRs, as described under Section 5.5.3, from a specific source to one or more sinks up to the amount of its GFA NITS Incremental Candidate ARRs subject to the total nomination limit described under Section 5.1.3;

(4) For each Eligible Entity with equivalent FPTP GFA service confirmed and verified following completion of the Annual TCR Auction Process, the Eligible Entity’s GFA FPTP Incremental Candidate ARRs for a specific source to sink pair is equal to the Reserved Capacity associated with that source to sink pair. An Eligible Entity may nominate GFA FPTP Incremental Candidate ARRs, as described under Section 5.5.2, for this specific source to sink pair up to the amount of its GFA FPTP Incremental Candidate ARRs subject to the total nomination limit described under Section 5.1.3.

Incremental Monthly ARR Nominations
Five (5) days prior to the start of each applicable Monthly TCR Auction Process, Eligible Entities may nominate in a single round process (i) NITS Incremental Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between their NITS ARR Nomination Cap and ARRs associated with NITS Candidate ARRs awarded in the Annual ARR Allocation process and NITS Candidate LTCRs awarded in the Annual ARR Allocation process; (ii) FPTP Incremental Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between their FPTP ARR Nomination Cap and ARRs associated with FPTP Candidate ARRs and FPTP Candidate LTCRs awarded in the Annual ARR Allocation process; (iii) GFA NITS Incremental Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between their GFA NITS ARR Nomination Cap and ARRs associated with GFA NITS Candidate ARRs and GFA NITS Candidate LTCRs awarded in the Annual ARR Allocation process; and/or (iv) GFA FPTP Incremental Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between their GFA FPTP ARR Nomination Cap and ARRs associated with GFA FPTP Candidate ARRs and GFA FPTP Candidate LTCRs awarded in the Annual ARR Allocation process. Nominations occur separately for On-Peak and Off-Peak periods. Eligible Entities submit the following information:

1. Source (valid candidate ARR source Settlement Location);
2. Sink (valid candidate ARR sink Settlement Location);
3. Class (on-peak or off-peak);
4. ARR MW.

(a) The total ARR MW nominated from a source Settlement Location cannot exceed the source Incremental candidate ARRs less previously awarded source ARRs.

5.5.3 Simultaneous Feasibility

The SFT to assess feasibility of nominated monthly candidate ARRs is performed as described under Section 5.3.2.3 with the following adjustments:

1. The SPP Transmission System model used in the SFT will be the same model to be used in the upcoming Monthly TCR Auction Process which will include the most up-to-date Network Model updated for forecasted transmission topology changes, including planned maintenance outages, and updated Parallel Flow assumptions;

(a) For withdrawals at sink Settlement Locations containing more than one PNode, SPP will distribute the Settlement Location withdrawal down to the PNode level...
using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. June for the month of July). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.6.

(2) LTCRs awarded in the Annual LTCR Allocation process are not modeled as fixed injections/withdrawals as they have already been accounted for as part of the Annual TCR Auction process and are included as TCRs as described under (4) below.

(3) 100% of the Residual SPP Transmission System Capability is made available; and

(4) All TCRs previously awarded in the Annual TCR Auction Process, TCRs associated with LTCRs that were awarded, and all remaining ARRs not accounted for in the Annual TCR Auction Process (as defined under Section 5.4), and for the applicable month are modeled as fixed injections at the specified sources and fixed withdrawals at the specified sinks. To the extent that these fixed injections and withdrawals are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to assessing ARR feasibility. SPP will report back to the MWG on a quarterly basis regarding the number of times that transmission line ratings had to be adjusted to ensure feasibility.

**5.5.4 Monthly ARR Awards**

If all of the nominated candidate ARRs are confirmed feasible, all nominated candidate ARRs are awarded in the form of ARRs. If the nominated candidate ARRs are not feasible, the amount of ARRs to be awarded will be reduced using a weighted least squares method. The weighted least squares method minimizes the least squares deviation from the nominated candidate ARR MW weighted by the reciprocal of the nominations resulting in a higher percentage ARR reduction for those candidate ARR nominations having the greatest impact on the constraints. ARR reductions associated with candidate ARR nominations that have an equal impact on the constraints are reduced by the same percentage.

**5.6 Monthly TCR Auction Processes**

The Monthly TCR Auction Process is the mechanism through which Market Participants may obtain TCRs over and above those obtained in the Annual TCR Auction Process through submission of TCR Bids to purchase TCRs and/or through conversion of remaining ARRs awarded in the Annual ARR Allocation Process and/or ARRs awarded in the ARR Allocation Process into TCRs through Self-Conversion. Market Participants may also offer for sale TCRs awarded in the Annual TCR Auction Process.
100% of the SPP Transmission System capability is made available during the Monthly TCR Auction Process. The remaining TCRs for the months of July through September are auctioned in a single-round process. The remaining TCRs for the months of October through May are auctioned in a two-round process. No later than three (3) Business Days prior the start of the Monthly TCR Auction Process, SPP will post the transmission system network topology data, along with corresponding Parallel Flow and transmission line outage assumptions, that SPP will use in the upcoming Monthly TCR Auction Process for use by Market Participants in developing their TCR Bid, TCR Offer and/or TCR self-conversion strategies. Exhibit 5-6 provides a representative timeline of the single-round and two-round Monthly TCR Auction Processes.
The following rules apply to the Monthly TCR Auction Processes:

5.6.1 **TCR Offer and Bid Submittal**

1. Any Market Participant that has satisfied the applicable credit requirements may participate in the Monthly TCR Auction Process;

2. Market Participants may submit TCR Bids and TCR Offers separately, for On-Peak and Off-Peak periods (two (2) separate transmission system models created). The following information is submitted for a TCR Bid or TCR Offer:
   a. Source (any valid Settlement Location);
   b. Sink (any valid Settlement Location);
   c. Class (on-peak or off-peak);
   d. Type (Bid, Offer or Self-Convert);
(e) TCR MW (0.1 MW increments, may not exceed ARR MW held on path if Self-Convert Type selected);

(f) TCR Price ($/MW);

   (i) TCR Bids and Offers cannot exceed $100,000/MW-Month;

   (ii) TCR Bids and Offers cannot be less than ($100,000/MW-Month).

3) For each TCR Round, a Market Participant is limited to a maximum combined submittal of 2000 TCR Bids and/or TCR Offers.

5.6.2 Monthly TCR Auction Process

TCRs are auctioned in a single-round process for the months of July through September and 100% of the SPP Residual Transmission System Capability, as calculated under Section 5.2.2(2) is made available. Any amounts of ARRs awarded in the Incremental Monthly ARR Allocation Process plus: the lesser of (i) 10% of the ARRs obtained in the Annual ARR Allocation Process or (ii) the difference between the ARRs obtained in the Annual ARR Allocation Process and the amount of Self-Converted TCRs awarded in the Annual TCR Auction Process may be Self-Converted during this single-round auction and any TCRs obtained in the Annual TCR Auction may be offered for sale.

TCRs are auctioned in a two-round process for the months of October through May. In the two-round process:

(1) Round 1 - 50% of the Residual SPP Transmission System Capability remaining following the Annual TCR Auction, as calculated under Section 5.2.2(2) is made available;

   (a) TCR Bids of the Self-Convert Type for any remaining ARRs may be submitted in this round for each source to sink pair that the Market Participant desires to convert that were obtained in the Annual ARR Allocation Process and/or ARRs obtained in the Incremental Monthly ARR Allocation Process into TCRs. The Self-Convert Type option will convert ARRs associated with the specified source to sink pair into the TCR MW specified subject to simultaneous feasibility;

   (i) Only Eligible Entities holding ARRs obtained in the Annual ARR Allocation Process and/or Incremental Monthly ARR Allocation Process may submit a Self-Convert TCR Bid.

   (ii) The Self-Convert TCR Bid must specify the same source and sink as the associated ARR and the TCR MW must be less than or equal to the associated ARR MW.
(iii) The lesser of: (i) 40% of the ARRs obtained in the Annual ARR Allocation Process or (ii) the difference between the ARRs awarded in the Annual ARR Allocation Process and the quantity of Self-Converted TCRs awarded in the Annual TCR Auction Process, plus all ARRs awarded in the Incremental Monthly ARR Allocation Process may be submitted for Self-Conversion.

(b) Any TCRs awarded in the Annual TCR Auction may be offered for sale.

(2) Round 2 - The remaining 50% of the Residual SPP Transmission System Capability, as calculated under Section 5.2.3 is made available;

(a) TCR Bids of the Self-Convert Type for any remaining ARRs may be submitted in this round for each source to sink pair that the Market Participant desires to convert where such remaining ARRs are determined as described under Section 5.6.2(c).

(b) Any TCRs awarded in Round 1 or the Annual TCR Auction, including Self-Converted TCRs, may be offered for sale.

5.6.3 Monthly TCR Auction Clearing and Simultaneous Feasibility

The Auction is performed using a Linear Program algorithm to maximize the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible:

(1) The SPP Transmission System topology used in the SFT will be the most up-to-date Network Model updated for forecasted transmission topology changes, including planned maintenance outages, for the auction month;

(a) For withdrawals at Settlement Locations containing more than one PNode, SPP will distribute the Settlement Location withdrawal down to the PNode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. June for the month of July). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.6.

(b) For injections at Market Hubs, SPP will distribute the hub injection down to the PNode level on a pro-rata basis using the weighting factors defined when the hub is created.

(2) The SFT is performed as described under Section except that LTCRs awarded in the Annual LTCR Allocation process are not modeled as fixed injections/withdrawals since they have already been awarded as self-converted TCRs, with TCR Bid MWs are
modeled as an injection at the source and a corresponding withdrawal at the sink. TCR Offers associated with the sale of existing TCRs are modeled as injections at the sink and withdrawals at the source. Residual SPP Transmission System Capability includes the most up to date Parallel Flow assumptions.

(a) For Round 1, all TCRs awarded in the Annual TCR Auction for the month are modeled as fixed injections and withdrawals. To the extent that the fixed injections and withdrawals representing TCRs awarded in the Annual TCR Auction are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to the Round 1 auction. SPP will report back to the MWG on a quarterly basis regarding the number of times that transmission line ratings had to be adjusted to ensure feasibility;

(b) For Round 2, all TCRs previously awarded for the month are modeled as fixed injections and withdrawals prior to clearing the TCR Bids and Offers.

5.6.4 Monthly TCR Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid and Offer prices such that the total TCR auction value is maximized. Self-Converted TCRs are evaluated simultaneously with submitted TCR Bids and Offers. Auction Clearing Prices (ACP) are calculated as described under Section 5.3.4.

5.7 ARR Allocation/TCR Auction Settlements

The charges and credits to ARR holders and TCR holders will be calculated on a daily basis and included on the settlement statements consistent with the timing of the Energy and Operating Reserve Markets settlement as described under Section 4.5.9.24. For the purposes of calculating charges and credits to ARR holders, the following amounts of ARR awards will be used:

(1) ARR Settlement for Annual TCR Auction by path:

(a) For the month of June, 100% of annual ARR award;
(b) For the months of July through September, the greater of (i) 90% of annual ARR award or (ii) Self-Convert TCR award;
(c) For the Fall, Winter and Spring season, the greater of (i) 60% of annual ARR award or (ii) Self-Convert TCR award.

(2) ARR Settlement for Monthly TCR Auction:
(a) For the months of July through September, remaining ARRs not accounted for in ARR Settlement as in the Annual TCR Auction as described in (1)(b) above plus all [incremental MCRR6.76] monthly ARR awards;

(b) For the months of October through May for Round 1, the greater of (i) (50% of [incremental MCRR6.77] monthly ARR awards plus: (50% of the difference between, the annual ARR award and the ARRs accounted for in the Annual TCR Auction as described in (1)(c) above) or (ii) Self-Convert TCR awards; and

(c) For the months of October through May for Round 2, the difference between:
   (i) the sum of annual ARR awards and [incremental MCRR6.78] monthly ARR awards and
   (ii) the sum of ARR MW accounted for under Section (1)(c) above and the ARR MW accounted for under Section (2)(b) above.

5.8 TCR Secondary Market

SPP will facilitate a secondary market for previously awarded TCRs as follows:

1. Bilateral trading of existing TCRs is facilitated through a bulletin board system;
2. TCRs may be broken down into 0.1 MW increments that total the original TCR;
3. TCRs may be traded daily, for On-Peak and/or Off-Peak periods;
4. Trades must be completed no later than two (2) calendar days prior to the applicable Operating Day to which the TCR instrument applies;
5. The TCR purchaser pays TCR seller directly;
6. TCRs may not be reconfigured (path must remain the same);
7. SPP accounts for transfer of TCR ownership; and

Both Purchaser and seller must be a Market Participant that has met applicable credit requirements.

Proposed Tariff Language Revision

Attachment AE

1.1 Definitions A

Auction Revenue Right ("ARR")

A right, awarded during the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process, which entitles the holder to a share of the auction
revenues generated in the applicable Transmission Congestion Rights auction(s), except for rights associated with LTCRs which are automatically converted to TCRs, and entitles the holder to self-convert the Auction Revenue Right to a Transmission Congestion Right.

**Auction Revenue Right Nomination Cap ("ARR Nomination Cap")**

A cap on the maximum total amount of Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

### 1.1 Definitions F

**Firm Point-To-Point Auction Revenue Right Nomination Cap**

The maximum total amount of Firm Point-To-Point Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

**Firm Point-To-Point Candidate Auction Revenue Right**

All or portion of the Megawatt quantity of a confirmed Firm Point-To-Point Transmission Service reservation which the holder of the Transmission Service reservation can nominate for conversion into an Auction Revenue Right in the Auction Revenue Right allocation process.

**Firm Point-To-Point Candidate Long-Term Congestion Right**

The Megawatt quantity of a confirmed Firm Point-To-Point Transmission Service reservation with rollover rights that is used by the Transmission Provider to determine available rights which the holder of the Transmission Service reservation can select for conversion into a Long-Term Congestion Right in the Long-Term Congestion Right allocation process.

### 1.1 Definitions G

**Grandfathered Agreement Firm Point-To-Point Auction Revenue Right Nomination Cap**
The maximum amount of Grandfathered Agreement Firm Point-To-Point Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process or the *monthly* Auction Revenue Right allocation process.

**Grandfathered Agreement Firm Point-To-Point Candidate Auction Revenue Right**

All or a portion of the Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Firm Point-To-Point Transmission Service, as defined in the Tariff which the applicable Eligible Entity can nominate for conversion into an Auction Revenue Right in the annual Auction Revenue Right allocation process.

**Grandfathered Agreement Firm Point-To-Point Candidate Long-Term Congestion Right**

The Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Firm Point-To-Point Transmission Service with rollover rights, which is used by the Transmission Provider to determine available rights that the applicable Eligible Entity can select for conversion into a Long-Term Congestion Right in the annual Long-Term Congestion Right allocation process.

**Grandfathered Agreement Network Integration Transmission Service Auction Revenue Right Nomination Cap**

The maximum amount of Grandfathered Agreement Network Integration Transmission Service Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

**Grandfathered Agreement Network Integration Transmission Service Candidate Auction Revenue Right**

All or a portion of the Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Network Integration Transmission Service, as defined in the Tariff, verified prior to the start of the annual ARR allocation process.
that the applicable Eligible Entity can nominate for conversion into an ARR in the ARR allocation process.

**Grandfathered Agreement Network Integration Transmission Service Candidate Long-Term Congestion Right**
The Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Network Integration Transmission Service verified prior to the start of the annual Long-Term Congestion Right allocation process, that is used by the Transmission Provider to determine available rights that the applicable Eligible Entity can select for conversion into a Long-Term Congestion Right during the Long-Term Congestion Right allocation process.

### 1.1 Definitions L

**Load Serving Entity (“LSE”)**
A distribution utility or an electric utility that has a service obligation, where a service obligation, as defined in Section 217(a) of the Federal Power Act, means a requirement applicable to, or the exercise of authority granted to, an electric utility under Federal, State, or local law or under long-term contracts to provide electric service to end-users or to a distribution utility.

**Long-Term Congestion Right (“LTCR”)**
An instrument that entitles the holder to a Transmission Congestion Right over a period of more than one year, which is awarded during the Transmission Provider’s annual Long-Term Congestion Rights allocation process.

### 1.1 Definitions N

**Network Integration Transmission Service Auction Revenue Right Nomination Cap**
The maximum amount of Network Integration Transmission Service Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

**Network Integration Transmission Service Candidate Auction Revenue Right**
The Megawatt quantity associated with Network Integration Transmission Service from Network Resources that the holder of the Network Integration Transmission Service can nominate for conversion into an Auction Revenue Right, subject to the Network Integration Transmission Service Auction Revenue Right Nomination Cap.

**Network Integration Transmission Service Candidate Long-Term Congestion Right**
The Megawatt quantity associated with Network Integration Transmission Service with rollover rights from Network Resources that is used by the Transmission Provider to determine available rights that the holder of the Network Integration Transmission Service can select for conversion into a Long-Term Congestion Right during the Long-Term Congestion Right allocation process.

### 1.1 Definitions S

**Simultaneous Feasibility Test**
A test for a state in which each set of injections and withdrawals associated with Long-Term Congestion Rights, Auction Revenue Rights and Transmission Congestion Rights would not exceed any thermal, voltage, or stability limits within the Transmission System under normal operating conditions or for monitored contingencies.

### 1.1 Definitions T

**Transmission Congestion Right (“TCR”)**
A right that entitles the holder to be compensated or charged for congestion in the Day-Ahead Market between two Settlement Locations.

**Transmission Congestion Rights Markets (“TCR Markets”)**
The annual Long-Term Congestion Rights allocation process, the annual and monthly Transmission Congestion Rights auctions and the Auction Revenue Rights annual and monthly allocation processes.

7.0 Transmission Congestion Rights Markets

The TCR Markets process includes an annual LTCR allocation, an annual ARR allocation, annual and monthly TCR auctions and a monthly ARR allocation in accordance with the timelines specified in the Market Protocols. The TCR Markets process is subject to review by the Market Monitor. LTCRs are obtained by Eligible Entities during the annual LTCR allocation. ARRs are obtained by Eligible Entities during the annual ARR allocation or the monthly ARR allocation. TCRs are obtained by Market Participants through the annual and monthly TCR auctions.

There are seven–eight (8) key processes associated with LTCRs, ARRs and TCRs:

(1) Annual LTCR/ARR verification;
(2) Annual ARR-LTCR allocation;
(3) Annual ARR allocation;
(4) Annual TCR auction;
(5) Monthly ARR allocation;
(6) Monthly TCR auction;
(7) ARR allocation and TCR auction settlements; and
(8) TCR secondary markets.

Table 7-1 in Section 7.3.2 of this Attachment AE provides additional details related to auction timing and Transmission System capability available for the TCR auctions.
7.1 **Annual Long-Term Congestion Right/Auction Revenue Right Verification**

Only Eligible Entities are permitted to nominate candidate LTCRs and/or ARRs. The following rules apply to verification of firm transmission service for conversion to LTCRs and/or ARRs.

7.1.1 **Transmission Service Verification**

In order for Eligible Entities to obtain candidate ARRs, the Transmission Provider must first verify existing transmission service entitlements, including transmission service entitlements that have been renewed in accordance with rollover rights since their initial term. An Eligible Entity’s transmission service must span the entire monthly or seasonal period for which ARRs are allocated to qualify for candidate ARRs in a particular month or season. An Eligible Entity’s transmission service must span the entire annual period for which LTCRs are allocated and must have rollover rights to qualify for candidate LTCRs. The Transmission Provider will verify Eligible Entity existing transmission service entitlements as follows:

(1) The following will be performed prior to each annual LTCR and ARR allocation for Eligible Entities taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff:

(a) The Transmission Provider will obtain source, sink and Reservation Capacity information from the OASIS for each monthly and seasonal period for which ARRs are allocated in which the transmission service spans the entire period for the current annual allocation and for the annual period for which LTCRs are allocated in which the transmission service spans the entire year:

(i) For a transmission service reservation with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Market Hub, the Transmission Provider will determine the load Settlement Location that most electrically corresponds to the source on the transmission service reservation that will be utilized as the source for candidate LTCRs and/or ARRs.
(ii) For a transmission service reservation with a source outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for candidate LTCRs and/or ARRs.

(iii) For a transmission service reservation with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for candidate LTCRs and/or ARRs.

(iv) Eligible Entities taking Network Integration Transmission Service with rollover rights under this Tariff shall be considered to have met the definition of a Load Serving Entity for purposes of LTCR allocation;

(v) Eligible Entities taking Firm Point-To-Point Transmission Service with rollover rights under this Tariff shall not be considered a Load Serving Entity for LTCR allocation purposes unless the Eligible Entity provides an attestation to the Transmission Provider confirming that the Eligible Entity is a Load Serving Entity as defined in this Attachment AE;

(b) The Transmission Provider will provide this information to each Eligible Entity for verification; and

(c) Eligible Entities will notify the Transmission Provider within 2 weeks following receipt of this information, identifying and correcting inaccurate data on the OASIS. Otherwise, the Transmission Provider provided data will be considered verified.

(2) The following will be performed prior to each annual LTCR and ARR allocation for the Eligible Entity taking GFA service:

(a) Each Transmission Owner shall register any GFA for which candidate LTCRs and/or ARRs are to be provided to the Transmission Owner or the
transmission customer under the GFA on the Transmission Provider’s OASIS. The Transmission Owner must provide the Transmission Provider with source, sink and Reservation Capacity information for each GFA on the Transmission Provider’s OASIS by registering each GFA with the Transmission Provider. The Transmission Provider will use source, sink, and Reservation Capacity information from the GFA registration for each monthly and seasonal period for which ARRs are allocated and the annual period for which LTCRs are allocated. If both parties to the GFA are Market Participants with respect to the GFA load, then the parties may jointly inform the Transmission Provider which Market Participant will be allocated the candidate LTCRs and/or ARRs. If the parties to the GFA do not so inform the Transmission Provider, or if only the Transmission Owner that sold the GFA service is a Market Participant, then the Transmission Owner that sold the GFA service will be allocated the candidate LTCRs and/or ARRs associated with the GFA.

(i) For a GFA with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Market Hub, the Transmission Provider will determine the load Settlement Location that most electrically corresponds to the source on the Transmission Service reservation that will be utilized as the source for candidate LTCRs and/or ARRs.

(ii) For a GFA with a source outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for the candidate LTCRs and/or ARRs.

(iii) For a GFA with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for the candidate LTCRs and/or ARRs.
(iv) An Eligible Entity under a GFA taking the equivalent of Network Integration Transmission Service with rollover rights shall be considered to have met the definition of Load Serving Entity for purposes of LTCR allocation;

(v) An Eligible Entity under a GFA taking the equivalent of Firm Point-To-Point Transmission Service with rollover rights shall not be considered a Load Serving Entity for the purposes of LTCR allocation unless the Eligible Entity provides an attestation to the Transmission Provider confirming that the Eligible Entity is a Load Serving Entity as defined in this Attachment AE:

(b) If the transmission customer under the GFA is receiving the candidate ARRs, to the extent that the transmission service specified in the GFA is identified as the equivalent of SPP Network Integration Transmission Service, the transmission customer under the GFA must provide the historical peak loads being served under the GFA for the previous three years.

7.1.2 Candidate Long-Term Congestion Rights/Auction Revenue Rights

Following verification of an Eligible Entity’s Transmission Service, candidate LTCRs and/or ARRs associated with such Transmission Service are assigned as follows:

(1) For each Eligible Entity with Network Integration Transmission Service, the Eligible Entity’s Network Integration Transmission Service Candidate LTCRs and/or Candidate ARRs from a specific source is equal to the source Reservation Capacity.

(a) An Eligible Entity may nominate/select Network Integration Transmission Service Candidate LTRsARRs, as described in Section 7.2.4 of this Attachment AE from a specific source to one or more sinks up to the amount of its available Network Integration Transmission Service Candidate ARRs—LTCRs
associated with the source subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(b) An Eligible Entity may nominate Network Integration Transmission Service Candidate ARRs, as described in Section 7.3.1 of this Attachment AE from a specific source to one or more sinks up to the amount of its Network Integration Transmission Service Candidate ARRs associated with the source subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(2) For each Eligible Entity with Firm Point-To-Point Transmission Service, the Eligible Entity’s Firm Point-To-Point Candidate LTCRs and/or ARRs for a specific source and sink is equal to the Reservation Capacity associated with that source and sink.

(a) An Eligible Entity may nominate LTCRs or ARRs, as described in Section 7.2.1 of this Attachment AE, for this specific source and sink up to the amount of its available Firm Point-To-Point Candidate LTCRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(b) Firm Point-To-Point Candidate ARRs may be nominated by an Eligible Entity, as described in Section 7.3.1 of this Attachment AE, for this specific source and sink up to the amount of its Firm Point-To-Point Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(3) For each Eligible Entity with equivalent Network Integration Transmission Service GFA service, the Eligible Entity’s Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs and/or ARRs from a specific source is equal to the source Reservation Capacity.

(a) An Eligible Entity may nominate LTCRs or ARRs, as described in Section 7.2.1 of this Attachment AE, from a specific source to one or more sinks up to the amount of its available Grandfathered
Agreement Network Integration Transmission Service Candidate LTCRsARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(b) An Eligible Entity may nominate Grandfathered Agreement Network Integration Transmission Service Candidate ARRs, as described in Section 7.3.1 of this Attachment AE, from a specific source to one or more sinks up to the amount of its Grandfathered Agreement Network Integration Transmission Service Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(4) For each Eligible Entity with equivalent Firm Point-To-Point GFA service, the Eligible Entity’s Grandfathered Agreement Firm Point-To-Point Candidate LTCRs and/or ARRs for a specific source and sink is equal to the Reservation Capacity associated with that source and sink.

(a) An Eligible Entity may nominate Grandfathered Agreement Firm Point-To-Point Candidate LTCRs and/or ARRs, as described in Section 7.2.1 of this Attachment AE, for this specific source and sink up to the amount of its Grandfathered Agreement Firm Point-To-Point Candidate LTCRsARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(b) An Eligible Entity may nominate Grandfathered Agreement Firm Point-To-Point Candidate ARRs, as described in Section 7.3.1 of this Attachment AE, for this specific source and sink up to the amount of its Grandfathered Agreement Firm Point-To-Point Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

7.1.3 Auction Revenue Right Nomination Cap

An Eligible Entity’s ARR Nomination Cap will be as follows:

(1) For Network Integration Transmission Customers, the Network Integration Transmission Service ARR Nomination Cap is equal to the minimum of a) the sum of Network Integration Transmission Service Candidate ARRs and Network
Integration Transmission Service Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Network Integration Transmission Service Candidate ARRs as calculated in Section 7.5.1 of this Attachment AE or b) One hundred and three percent (103%) of the average of that customer’s three most recent annual peak Network Loads. This value will be adjusted by the Transmission Provider as required to account for wholesale load shifts between Transmission Customers. In addition, candidate LTCRs and awarded LTCRs shall be transferred by the Transmission Provider as applicable to account for wholesale load shifts between Transmission Customers.

(2) For Firm Point-To-Point Transmission Customers, the Firm Point-To-Point ARR Nomination Cap is equal to the sum of Firm Point-To-Point Candidate ARRs and Firm Point-To-Point Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Firm Point-To-Point Candidate ARRs as calculated in Section 7.5.1 of this Attachment AE.

(3) For GFA customers taking the equivalent of SPP Network Integration Transmission Service, the Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap is equal to the minimum of a) the sum of Grandfathered Agreement Network Integration Transmission Service Candidate ARRs and Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Grandfathered Agreement Network Integration Transmission Service Incremental Candidate ARRs as calculated in Section 7.5.1 of this Attachment AE or b) One hundred and three percent (103%) of the average of that GFA’s customer’s three most recent annual peak Network Loads.

(4) For GFA customers taking the equivalent of SPP Firm Point-To-Point, the Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap is equal to the sum of Grandfathered Agreement Firm Point-To-Point Candidate ARRs and Grandfathered Agreement Firm Point-To-Point Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Grandfathered Agreement
Firm Point-To-Point Candidate ARRs as calculated in Section 7.5.1 of this Attachment AE.


7.2 Annual Long-Term Congestion Right Allocation

Eligible Entities may select the candidate LTCRs that they wish to receive up to their available LTCRs. The portion of the selected candidate ARRs are awarded to each Eligible Entity during the LTCR annual allocation. Available Candidate LTCRs are evaluated on an annual basis in a two-step process; (i) Candidate LTCRs associated with Eligible Entities that are Load Serving Entities are evaluated in accordance with Section 7.2.2 and (ii) remaining Candidate LTCRs associated with Eligible Entities that are not Load Serving Entities are then evaluated in accordance with Section 7.2.3.

The Transmission Provider shall make available fifty percent (50%) of the projected maximum Transmission System capability for the purpose of LTCR allocation in the annual LTCR allocation process. No later than five (5) days prior to the start of the annual LTCR allocation process, the Transmission Provider shall post the Transmission System network topology, including the corresponding impacts from Parallel Flow, used to determine the projected maximum Transmission System capability that will be used in the upcoming allocation.

7.2.1 LTCR Surrender

Eligible Entities may surrender previously awarded LTCRs in 0.1 MW increments. Prior to annual LTCR allocation, Eligible Entities shall submit the following information:

(1) Source (valid candidate LTCR source Settlement Location);

(2) Sink (valid candidate LTCR sink Settlement Location);
Surrendered LTCR MW (cannot exceed previously awarded LTCR).

7.2.2 Available Long-Term Congestion Rights for Load Serving Entities

A Simultaneous Feasibility Test is performed to determine the amount of available LTCRs that may be selected and awarded for Eligible Entities that are LSEs. The Simultaneous Feasibility Test is performed using the most current Network Model for the corresponding LTCR allocation period. For the Simultaneous Feasibility Test, all candidate Load Serving Entity LTCRs are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. In addition, all previously awarded LTCRs, that have not been surrendered, which are associated with Eligible Entities that are not LSEs, are modeled as fixed injections and withdrawals.

If the candidate Load Serving Entity LTCRs are not feasible, the amount of candidate LTCRs available for selection and award will be reduced using a weighted least squares method. The weighted least squares method minimizes the sum of the squared deviations between the actual LTCR amounts and the candidate LTCR amounts, weighted by the reciprocal of the candidate LTCR amounts, which results in a higher percentage LTCR reduction for those nominations having the greatest impact on the constraints. LTCR reductions associated with candidates that have an equal impact on the constraints are reduced by the same percentage.

Previously awarded Load Serving Entity LTCRs are guaranteed to be available using the iterative methodology described in the Market Protocols; provided that such Load Serving Entity LTCRs must meet the criteria as specified in Section 7.1.1 of this Attachment AE, or have not been surrendered as described under Section 7.2.1 of this Attachment AE. To the extent that these previously awarded Load Serving Entity LTCRs are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution.

7.2.3 Available Long-Term Congestion Rights for Non-Load Serving Entities
A Simultaneous Feasibility Test is performed to determine the amount of available LTCRs that may be selected and awarded for Eligible Entities that are not Load Serving Entities. The Simultaneous Feasibility Test is performed using the most current Network Model for the corresponding LTCR allocation period. For the Simultaneous Feasibility Test, all candidate non-Load Serving Entity LTCRs are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. In addition all available LTCRs associated with Eligible Entities that are Load Serving Entities as calculated under Section 7.2.2 of this Attachment AE are modeled as fixed injections and withdrawals.

If the candidate non-Load Serving Entity LTCRs are not feasible, the amount of candidate LTCRs available for selection and award will be reduced using a weighted least squares method. The weighted least squares method minimizes the sum of the squared deviations between the actual LTCR amounts and the candidate LTCR amounts, weighted by the reciprocal of the candidate LTCR amounts, which results in a higher percentage LTCR reduction for those nominations having the greatest impact on the constraints. LTCR reductions associated with candidates that have an equal impact on the constraints are reduced by the same percentage.

Previously awarded non-Load Serving Entity LTCRs are guaranteed to be available using the iterative methodology described in the Market Protocols; provided that such non-Load Serving Entity LTCRs must meet the criteria as specified in Section 7.1.1 of this Attachment AE, or which have not been surrendered as described under Section 7.2.1 of this Attachment AE. To the extent that these previously awarded non-Load Serving Entity LTCRs are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution.

7.2.4 LTCR Selection and Awards

(1) All previously awarded LTCRs are automatically awarded as LTCRs for the current allocation year; provided that such LTCRs meet the criteria specified in Section 7.1.1 of this Attachment AE; or were not surrendered as described under Section 7.2.1 of this Attachment AE.
(2) Additional LTCRs are selected and awarded in a single-round process. Eligible Entities may select:

(a) Available LTCRs from its Network Integration Transmission Service Candidate LTCRs, less any previously awarded LTCRs plus any surrendered LTCRs associated with Network Integration Transmission Service Candidate LTCRs;

(b) Available LTCRs from its Firm Point-To-Point Candidate LTCRs, less any previously awarded LTCRs plus any surrendered LTCRs associated with Firm Point-To-Point Candidate LTCRs;

(c) Available LTCRs from its Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs as described under Section 7.1.2, less any previously awarded LTCRs plus any surrendered LTCRs associated with Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs; and/or

(d) Available LTCRs from its Grandfathered Agreement Firm Point-To-Point Candidate LTCRs as described under Section 7.1.2, less any previously awarded LTCRs plus any surrendered LTCRs associated with Grandfathered Agreement Firm Point-To-Point Candidate LTCRs;

(3) Eligible Entities shall submit the following information in order to select LTCRs that were not previously awarded:

(a) Source (valid candidate LTCR source Settlement Location);

(b) Sink (valid candidate LTCR sink Settlement Location);

(c) LTCR MW (total LTCR MW selected from a source Settlement Location cannot exceed the source candidate available LTCR MW as previously determined under Section 7.2.2 or Section 7.2.3, less previously awarded LTCRs plus surrendered LTCRs);

(4) All selected LTCRs are automatically awarded.
7.23 Annual Auction Revenue Right Allocation

The annual ARR allocation addresses how candidate ARRs verified in the annual LTCR/ARR verification may be nominated and awarded. Eligible Entities may nominate the candidate ARRs that they wish to receive up to their ARR nomination caps less any LTCRs awarded. The portion of the nominated candidate ARRs that are simultaneously feasible are allocated to each Eligible Entity during the annual allocation. Candidate ARRs are nominated on a monthly and seasonal basis in a three round process.

The Transmission Provider shall make available one hundred percent (100%) of the projected maximum Transmission System capability for the purpose of ARR allocation in the annual ARR allocation process. No later than five (5) days prior to the start of the annual ARR allocation process, the Transmission Provider will post the Transmission System network topology data for each of the monthly and seasonal On-Peak and Off-Peak models, including the corresponding Parallel Flow and transmission line outage assumptions, used to determine the projected maximum Transmission System capability that will be used in the upcoming allocations.

7.3.1 Auction Revenue Right Nominations

For each month and season included in the annual ARR allocation period, as defined in Table 7-1 in Section 7.3.2 of this Attachment AE, Eligible Entities may nominate candidate ARRs in 0.1 MW increments for specific source to sink pairs that total up to their ARR nomination caps as calculated in Section 7.1.3 of this Attachment AE less any LTCRs awarded. Nominations occur separately for On-Peak and Off-Peak periods. Prior to each ARR nomination round, Eligible Entities shall submit the following information:

1. Source: valid candidate ARR source Settlement Location for rounds 1 and 2, and any applicable source Settlement Location for round 3;
2. Sink: valid candidate ARR sink Settlement Location for rounds 1 and 2, and any applicable sink Settlement Location for round 3;
3. Class: On-Peak or Off-Peak;
4. Period: specific month or season; and
(5) Nominated ARR MW:
(a) In round 1 and round 2, the total candidate ARR MW nominated from a source Settlement Location cannot exceed the source candidate ARRs less any awarded LTCRs associated with the source.
(b) In round 3, any source to sink path may be nominated, subject to the limitation described in Section 7.23.2(3) of this Attachment AE.

7.23.2 Auction Revenue Right Allocation

ARRs are allocated in a three round process as follows:

(1) In round 1, Eligible Entities may nominate:
(a) ARRs from their Network Integration Transmission Service Candidate ARRs that totals no more than fifty percent (50%) of their Network Integration Transmission Service ARR Nomination Cap less the sum of awarded LTCRs from their Network Integration Transmission Service Candidate LTCRs;
(b) ARRs from their Grandfathered Agreement Network Integration Transmission Service Candidate ARRs that totals no more than fifty percent (50%) of their Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap less the sum of awarded LTCRs from their Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs;
(c) ARRs from their Firm Point-To-Point Candidate ARRs that totals no more than fifty percent (50%) of their Firm Point-To-Point ARR Nomination Cap less the sum of awarded LTCRs from their Firm Point-To-Point Candidate LTCRs; and
(d) ARRs from their Grandfathered Agreement Firm Point-To-Point Candidate ARRs that totals no more than fifty percent (50%) of their Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap less
the sum of awarded LTCRs from their Grandfathered Agreement Firm Point-To-Point Candidate LTCRs.

(2) In round 2, Eligible Entities may nominate:
(a) ARRs from their Network Integration Transmission Service Candidate ARRs that totals no more than one hundred percent (100%) of their Network Integration Transmission Service ARR Nomination Cap less any nominated Network Integration Transmission Service Candidate ARRs awarded in round 1 less the sum of awarded LTCRs from their Network Integration Transmission Service Candidate LTCRs;
(b) ARRs from their Grandfathered Agreement Network Integration Transmission Service Candidate ARRs that totals no more than one hundred percent (100%) of their Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap less any nominated Grandfathered Agreement Network Integration Transmission Service Candidate ARRs awarded in round 1 less the sum of awarded LTCRs from their Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs;
(c) ARRs from their Firm Point-To-Point Candidate ARRs that totals no more than one hundred percent (100%) of their Firm Point-To-Point ARR Nomination Cap less any nominated Firm Point-To-Point Candidate ARRs awarded in round 1 less the sum of awarded LTCRs from their Firm Point-To-Point Candidate LTCRs; and
(d) ARRs from their Grandfathered Agreement Firm Point-To-Point Candidate ARRs that totals no more than one hundred percent (100%) of their Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap less any nominated Grandfathered Agreement Firm Point-To-Point Candidate ARRs awarded in round 1 less the sum of awarded LTCRs from their Grandfathered Agreement Firm Point-To-Point Candidate LTCRs.

(3) In round 3, any Eligible Entity may nominate ARRs from any source to sink that totals no more than one hundred percent (100%) of its ARR Nomination Cap less
any nominated candidate ARR amounts awarded in rounds 1 and 2 less the sum of all awarded LTCRs. In this round an Eligible Entity is limited to a maximum combined submittal of two-thousand (2,000) ARR nominations for each Asset Owner it represents.

### 7.32.3 Annual Auction Revenue Right Awards

A Simultaneous Feasibility Test is performed in each round of the ARR allocation to determine the amount of nominated ARRs to be awarded. The Simultaneous Feasibility Test is performed using the most current Network Model projected including planned transmission outages for the corresponding ARR allocation period. For the Simultaneous Feasibility Test, a nominated candidate ARR is modeled as a generation injection at the source and a corresponding load withdrawal at the sink. All awarded LTCRs are modeled as fixed injections and withdrawals and are automatically awarded as ARRs.

If the nominated candidate ARRs are not feasible, the amount of nominated candidate ARRs to be awarded will be reduced using a weighted least squares method. The weighted least squares method minimizes the sum of the squared deviations between the actual ARR amounts and the nominated ARR amounts, weighted by the reciprocal of the nominated ARR amounts, which results in a higher percentage ARR reduction for those nominations having the greatest impact on the constraints. ARR reductions associated with nominations that have an equal impact on the constraints are reduced by the same percentage.

Every six (6) months for the first two (2) years after implementation of the Integrated Marketplace, the Transmission Provider will analyze the net funding of TCRs through the Day-Ahead Market. In the event the cumulative funding is at or below 90% or above 100%, the Transmission Provider may approve an additional adjustment of all subsequent monthly auctions and the month of June in the annual auction of the normal and emergency ratings of all flowgates and monitored transmission system elements.
7.43 Annual Transmission Congestion Right Auction

Market Participants may obtain TCRs by purchasing them in the annual TCR auction or through conversion of ARRs into TCRs. LTCRs awarded as ARRs as described under Section 7.3.3 are automatically converted to TCRs which the holder may offer for sale in the auction. The percentages of the Transmission System capability made available during the annual TCR auction are listed in Table 7-1 in Section 7.3.2 of this Attachment AE. TCRs in the annual auction are auctioned in a single round process for all months and seasons. If there are any changes to the transmission system topology or Parallel Flow data after the conclusion of Annual ARR Allocation Process, the Transmission Provider will post such changes no later than three (3) Business Days prior to the start of the Annual TCR Auction Process.

7.34.1 Transmission Congestion Right Offer and Bid Submittal

(1) Market Participants that have satisfied the applicable credit requirements may participate in the annual TCR auction.

(2) Market Participants holding ARRs associated with a specific source and sink may elect to self-convert all or a portion of those ARRs into TCRs by specifying the self-convert option as part of the TCR Bid submittal.

(3) For each month and season included in the annual TCR auction, Market Participants may submit TCR Bids and/or Offers in 0.1 MW increments, for On-Peak and Off-Peak periods. A valid TCR Bid and/or Offer must contain the following information:

(a) Source: any valid Settlement Location;
(b) Sink: any valid Settlement Location;
(c) Class: On-Peak or Off-Peak;
(d) Period: specific month or season;
(e) Type: Bid, Offer or self-convert;
(f) TCR MW; and
(g) TCR Price;

(i) TCR Bids and Offers cannot exceed $100,000/MW-Month;
(ii) TCR Bids and Offers cannot be less than negative $100,000/MW-Month;

(4) For each TCR round, a Market Participant is limited to a maximum of 2,000 TCR Bids and/or Offers for each Asset Owner it represents.
7.43.2 Annual Transmission Congestion Right Auction

In the annual TCR auction, TCRs are made available in a single round for each month and season as follows:

(1) For the month of June, one hundred percent (100%) of the Transmission System capability is made available, for the July-September period ninety percent (90%) is made available, and for the Fall, Winter and Spring seasons sixty percent (60%) is made available. For additional details see Table 7-1;

(a) Only Eligible Entities holding ARRs may submit a self-convert TCR Bid.

(b) The self-convert TCR MWs are evaluated simultaneously with TCR Bids and Offers and are subject to reductions that may result from the Simultaneous Feasibility Test.

(c) The self-convert TCR Bid or Offer must specify the same source and sink as the associated ARR and the TCR MW must be less than or equal to the associated ARR MW.

(d) The self-convert type option will convert ARRs associated with the specified source to sink pair into the TCR MW specified subject to simultaneous feasibility.
Table 7-1: TCR Auction Summary

<table>
<thead>
<tr>
<th>Auction Month</th>
<th>Auction Type</th>
<th>TCR Award Periods</th>
<th>TCR Product</th>
<th>Auction Rounds</th>
<th>Total Auctions</th>
</tr>
</thead>
<tbody>
<tr>
<td>May (System Capability %)</td>
<td>Annual</td>
<td>Jun (100)</td>
<td>Jul (90)</td>
<td>Aug (90)</td>
<td>Sep (90)</td>
</tr>
<tr>
<td>Jun (System Capability %)</td>
<td>Monthly</td>
<td>Jul (100)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jul (System Capability %)</td>
<td>Monthly</td>
<td>Aug (100)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aug (System Capability %)</td>
<td>Monthly</td>
<td>Sep (100)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sep (System Capability %)</td>
<td>Monthly</td>
<td>Oct (100)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oct (System Capability %)</td>
<td>Monthly</td>
<td>Nov (100)</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Nov (System Capability %)</td>
<td>Monthly</td>
<td>Dec (100)</td>
<td></td>
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<tr>
<td>Dec (System Capability %)</td>
<td>Monthly</td>
<td>Jan (100)</td>
<td></td>
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<tr>
<td>Jan (System Capability %)</td>
<td>Monthly</td>
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<tr>
<td>Feb (System Capability %)</td>
<td>Monthly</td>
<td>Mar (100)</td>
<td></td>
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<tr>
<td>Mar (System Capability %)</td>
<td>Monthly</td>
<td>Apr (100)</td>
<td></td>
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</tr>
<tr>
<td>Apr (System Capability %)</td>
<td>Monthly</td>
<td>May (100)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
October and November

December, January, February, March

April and May

7.34.3 Annual Transmission Congestion Right Auction Clearing and Simultaneous Feasibility

The auction is performed with an objective of maximizing the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible. A Simultaneous Feasibility Test is performed in each round.

The Simultaneous Feasibility Test is performed using the most up to date Network Model projected including planned transmission outages for the corresponding ARR allocation period. For the Simultaneous Feasibility Test:

(1) TCR submittals of both the self-convert type and Bid type are modeled as a generation injection at the source and a corresponding load withdrawal at the sink;

(2) TCR submittals of the Offer type are modeled as a generation injection at the sink and a corresponding load withdrawal at the source; and

(3) ARRs associated with LTCRs are automatically converted into awarded TCRs, are modeled as fixed injections and withdrawals, and such TCRs are treated as self-converted TCRs for settlement purposes.

7.34.4 Annual Transmission Congestion Right Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid prices such that the total TCR auction value is maximized. Self-converted TCRs are evaluated concurrently with all other submitted TCR Bids and are given the highest priority subject to simultaneous feasibility.

In the event there is a tie during the Simultaneous Feasibility Test, each competing TCR Bid and Offer will be awarded a TCR on a pro rata share based on the individual impact on the constraint. ACPs are calculated based on the shift factor for a specific bus to the Reference Bus with the corresponding Shadow Price for such bus, for each Settlement Location using the formula for the MCC as described in Section 8.3.1.2 of this Attachment AE.
7.54 Monthly Transmission Congestion Right Auctions

Market Participants may obtain TCRs, in addition to those obtained in the annual TCR auction, by purchasing TCRs in the monthly TCR auction or through conversion of ARRs awarded in the annual and *monthly* ARR allocations. Market Participants may also offer for sale TCRs awarded in the annual TCR auction. The TCRs for the months of July through September are auctioned in a single round. The TCRs for the months of October through May are auctioned in two rounds. No later than three (3) days prior to the monthly TCR auction, the Transmission Provider will post any changes to the Transmission System topology or input data assumptions that occurred after the conclusion of the annual ARR allocation.

7.54.1 Monthly Transmission Congestion Right Offer and Bid Submittal

(1) Market Participants that have satisfied the applicable credit requirements may participate in the monthly TCR auction.

(2) Market Participants may submit TCR Bids and Offers for On-Peak and Off-Peak periods. The following information is submitted for a TCR Bid or Offer:

(a) Source: any valid Settlement Location;
(b) Sink: any valid Settlement Location;
(c) Class: On-Peak or Off-Peak;
(d) Type: Bid, Offer or self-convert;
(e) TCR MW: 0.1 MW increments, may not exceed ARR MW held on path if self-convert type selected; and
(f) TCR Price:
   (i) TCR Bids cannot exceed $100,000/MW-Month;
   (ii) TCR Bids cannot be less than negative $100,000/MW-Month;

(3) Market Participants may not submit more than a total of 2,000 TCR Bids and Offers in each TCR round for each Asset Owner it represents.

7.54.2 Monthly Transmission Congestion Right Auction

TCRs are auctioned in a single round for the months of July through September and one hundred percent (100%) of the Transmission System capability is made available. Any amounts of ARRs awarded in the *monthly* ARR allocation plus: the lesser of (i) ten percent (10%) of the
ARRs obtained in the annual ARR allocation or (ii) the difference between the ARRs obtained in the annual ARR allocation and the amount of self-converted TCRs awarded in the annual TCR auction may be self-converted during this auction and any TCRs obtained in the annual TCR auction may be offered for sale.

TCRs are auctioned in a two round process for the months of October through May. In the two round process:

(1) Round 1 - Fifty percent (50%) of the Transmission System capability remaining following the annual TCR auction is made available;

(a) All ARRs awarded in the Monthly ARR Allocation Process may be submitted for self-conversion.

(i) ARRs obtained in the annual allocation may be submitted for self-conversion subject to the following limitations: Eligible Entities may submit the lesser of (i) forty percent (40%) of the ARRs obtained in the annual ARR allocation or (ii) the difference between the ARRs awarded in the annual ARR allocation and the quantity of self-converted TCRs awarded in the annual TCR auction.

(ii) A self-convert TCR Bid must specify the same source and sink as the associated ARR and must be less than or equal to the associated ARR MW.

(iii) The self-convert TCR MWs are evaluated simultaneously with TCR Bids and Offers and are subject to reductions that may result from the Simultaneous Feasibility Test.

(b) Any TCRs awarded in the annual TCR auction may be offered for sale by the TCR holder.

(d) Any Market Participant may also submit TCR Bids for any source-sink pair.

(2) Round 2 - The remaining Transmission System capability is made available;

(a) An Eligible Entity may submit self-convert TCR Bids in this round that are limited to the values calculated under Section 7.67(2)(c) of this Attachment AE. The self-convert TCR MWs are evaluated simultaneously with TCR Bids and Offers and are subject to reductions that may result from the Simultaneous Feasibility Test.

(b) Any TCRs awarded in round 1 or the annual TCR auction, including self-converted TCRs, may be offered for sale by the TCR holder.
Any Market Participant may also submit TCR Bids for any source-sink pair.

### 7.54.3 Monthly Transmission Congestion Right Auction Clearing and Simultaneous Feasibility

The auction is performed with an objective of maximizing the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible. A Simultaneous Feasibility Test is performed in each round using the most up to date Network Model projected including planned transmission outages for the corresponding monthly TCR auction period with all TCRs awarded in the annual TCR auction modeled as fixed injections and withdrawals. To the extent that these fixed injections and withdrawals are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution prior to the start of the monthly TCR auction solely for the purpose of the monthly TCR auction. The Transmission Provider will report to the stakeholders on a quarterly basis regarding the number of times that the transmission facility ratings had to be adjusted in the model to ensure feasibility.

For the Simultaneous Feasibility Test, monthly TCR submittals of the self-convert type and TCR Bid type are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. A monthly TCR submittal of the Offer type is modeled as a generation injection at the sink and a load withdrawal at the source.

### 7.54.4 Monthly Transmission Congestion Right Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid prices such that the total TCR auction value is maximized. Self-converted TCRs are evaluated concurrent with all other submitted TCR Bids and are given the highest priority subject to simultaneous feasibility. ACPs are calculated for each Settlement Location using the formula for the MCC as described in Section 8.3.1.2 of this Attachment AE.

### 7.65 Monthly Auction Revenue Right Allocation

Eligible Entities are eligible to nominate candidate ARRs associated with such services for each remaining month in the current annual ARR allocation period for: (i) any remaining candidate ARR capacities from the Annual ARR Allocation Process, (ii) firm Transmission
Service that has been confirmed following the completion of the most recent annual TCR auction and prior to the next annual LTCR/ARR verification, (iii) firm Transmission Service confirmed prior to the Annual LTCR/ARR Verification Process that includes a partial season, or (iv) Transmission Service for which a redispatch obligation has been eliminated. To the extent that the Eligible Entity’s firm Transmission Service term extends beyond the current annual ARR allocation period, such remaining service will be included in the next annual LTCR/ARR verification.

7.65.1 Monthly Auction Revenue Right Transmission Service Verification

In order to qualify for additional monthly candidate ARRs in a particular month, an Eligible Entity’s Transmission Service must span the entire month within the applicable year. The Transmission Provider will verify Eligible Entity existing Transmission Service entitlements as follows:

(1) The Transmission Provider will obtain the source, sink and Reservation Capacity information from the Transmission Provider’s OASIS for the applicable month;

(2) The Transmission Provider will provide this information to each Eligible Entity for verification; and

(3) Eligible Entities will notify the Transmission Provider within six (6) days following receipt of this information, identifying and correcting inaccurate data on the OASIS. Otherwise, the Transmission Provider provided data will be considered verified and additional monthly candidate ARRs will be assigned as described under Section 7.1.2.

7.65.3 Monthly Auction Revenue Right Nominations

Five (5) days prior to the start of the monthly TCR auction, Eligible Entities may nominate in a single round: (i) Network Integration Transmission Service Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between their Network Integration Transmission Service ARR Nomination Cap and ARRs associated with Network Integration Transmission Service Candidate ARRs and Network Integration Transmission Service Candidate LTCRs awarded in the annual ARR allocation; (ii) Firm Point-To-Point Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between their Firm Point-To-Point ARR Nomination Cap and ARRs associated with Firm Point-To-Point Candidate ARRs and Firm Point-To-Point

Candidate LTCRs awarded in the annual ARR allocation; (iii) Grandfathered Agreement Network Integration Transmission Service Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between their Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap and ARRs associated with Grandfathered Agreement Network Integration Transmission Service Candidate ARRs and Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs awarded in the annual ARR allocation; and (iv) Grandfathered Agreement Firm Point-To-Point Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between their Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap and ARRs associated with Grandfathered Agreement Firm Point-To-Point Candidate ARRs and Grandfathered Agreement Firm Point-To-Point Candidate LTCRs awarded in the annual ARR allocation. Nominations occur separately for On-Peak and Off-Peak periods. Eligible Entities submit the following information:

1. Source: valid candidate ARR source Settlement Location;
2. Sink: valid candidate ARR sink Settlement Location;
3. Class: On-Peak or Off-Peak; and
4. ARR MW:
   a. The total ARR MW nominated from a source Settlement Location cannot exceed the source candidate ARRs less previously awarded source ARRs.

### 7.65.4 Monthly Auction Revenue Rights Awards

A Simultaneous Feasibility Test is performed to determine the amount of nominated candidate ARRs to be awarded. For the Simultaneous Feasibility Test a nominated candidate ARR is modeled as a generation injection at the source and a corresponding load withdrawal at the sink. The Simultaneous Feasibility Test is performed using the following assumptions.

1. The Transmission System model used in will be the same Network Model to be used in the upcoming monthly TCR auction;
2. One hundred percent (100%) of the projected maximum Transmission System capability, including any completed Network Upgrades, is made available; and
3. All TCRs previously awarded in the annual TCR auction and all remaining ARRs not accounted for in the annual TCR auction (as defined in Section 7.76 of this Attachment AE) for the applicable month are modeled as fixed injections at the
specified sources and fixed withdrawals at the specified sinks. To the extent that these fixed injections and withdrawals are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution solely for the purpose of assessing ARR feasibility. The Transmission Provider will report to the stakeholders on a quarterly basis regarding the number of times that the transmission facility ratings had to be adjusted in the model to ensure feasibility.

If the nominated candidate ARRs are not feasible, the amount of nominated candidate ARRs to be awarded will be reduced based on their relative impact on the constraint to produce a simultaneously feasible result.

7.76 Auction Revenue Right Allocation and Transmission Congestion Right Auction Settlements

The charges and payments to ARR and TCR holders will be calculated on a daily basis and included on the Settlement Statements consistent with the timing of the Energy and Operating Reserve Markets settlement as described in Section 8.7 of this Attachment AE. For the purposes of calculating charges and payments to ARR holders, the following amounts of ARR awards will be used:

(1) ARR Settlement for annual TCR auction:
   (a) For the month of June, one hundred percent (100%) of annual ARR award;
   (b) For the months of July through September, the greater of (i) ninety (90%) of annual ARR award or (ii) self-convert TCR award; and
   (c) For the Fall, Winter and Spring seasons, the greater of (i) sixty (60%) of annual ARR award or (ii) self-convert TCR award.

(2) ARR Settlement for monthly TCR auction:
   (a) For the months of July through September, ARRs not accounted for in ARR Settlement in the annual TCR auction as described in (1)(b) above plus all monthly ARR awards;
   (b) For the months of October through May for round 1, the greater of (i) fifty (50%) of monthly ARR awards plus: fifty percent (50%) of the difference between the annual ARR award and the ARRs accounted for in the annual
TCR auction as described in (1)(c) above or (ii) Self-convert TCR awards; and

(c) For the months of October through May for round 2, the difference between: (i) the sum of annual ARR awards and monthly ARR awards and (ii) the sum of ARR MW accounted for in Section (1)(c) above and the ARR MW accounted for in Section (2)(b) above.

7.78 Transmission Congestion Right Secondary Market

The Transmission Provider will facilitate a secondary market for TCRs. Both purchaser and seller in the secondary market must be a Market Participant. The secondary market is described as follows:

1. Bilateral trading of existing TCRs is facilitated through a bulletin board system;
2. TCRs may be broken down into increments that are not smaller than 0.1 MW and that totals no more than the original TCR;
3. TCRs may be traded daily, for On-Peak or Off-Peak periods;
4. Trades must be completed no later than two (2) calendar days prior to the applicable Operating Day to which the TCR instrument applies.
5. The TCR purchaser pays TCR seller directly;
6. TCRs may not be reconfigured (path must remain the same);
7. The Market Participants must inform the Transmission Provider of any proposed transfer and the Transmission Provider must confirm that the credit requirements in Attachment X of this Tariff have been met prior to the transfer of ownership of a TCR through a bilateral transaction; and
8. The Transmission Provider records the transfer of TCR ownership.

7.89 Liquidation of Transmission Congestion Rights in the Event of Market Participant Default

In the event the Transmission Provider declares a Market Participant to be in default in accordance with Attachment X of this Tariff, the Transmission Provider shall initiate the following procedures to close out and liquidate the TCRs of the Market Participant as soon as practicable after such default is declared:

1. Transmission Provider may close out the defaulting Market Participant’s positions as of the date of default, by unilaterally accelerating and terminating all forward TCR positions.
(2) Transmission Provider shall post on its website all salient information relating to a closed out portfolio of TCRs.

(3) In liquidating the defaulting Market Participant’s TCR portfolio, the Transmission Provider shall not allow the liquidated TCRs offered for sale to set price.

(4) Transmission Provider may offer for sale all of the TCR positions within the defaulting Market Participant’s TCR portfolio in any or all upcoming regularly scheduled TCR auctions.

(5) Alternatively, the Transmission Provider may conduct one or more specially scheduled TCR auctions, in which all of the portfolio of the defaulting Market Participant’s TCRs are offered for sale.

(6) If Transmission Provider elects not to, or is unable to, close out and liquidate a TCR position under these procedures, the close out shall be deemed void and the defaulting Market Participant shall remain liable for the full final value of its default, such full final value being based upon the results of the applicable Day-Ahead Market settlements.

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7.9 Initial TCR Markets Schedule

For the initial period, which will span the period between the start-up date of the Marketplace and the start date for the first annual TCR year, Transmission Provider will conduct an abbreviated multi-month auction using a process similar to the annual auction. The initial production schedule for TCRs shall be as follows and in accordance with the timelines specified in the Market Protocols:

1. Candidate ARR Verification

2. 3-round ARR Market Participant Nomination and Transmission Provider Allocation processes

3. 1-round TCR Auction for the period prior to the first full year auction using 90% of the system capability

Subsequently, Transmission Provider will conduct monthly auctions of any residual amounts available on the system according to the process defined for monthly auctions in Sections 7.4 and 7.5 of this Attachment AE.
Attachment X

2.1 Definitions. The following definitions apply in this Credit Policy. Capitalized terms used herein and not defined herein shall be given the meaning assigned to them under the Tariff.

**Locational Marginal Price**
This term shall have the meaning given in Attachment AE of the Tariff.

**Long-Term Congestion Right (LTCR)**
This term shall have the meaning given in Attachment AE of this Tariff.

**Market Exposure**
This term has the meaning given in Section 5.2.1.

5A.1 Overview.

5A.1.1 Transmission Congestion Rights create potential exposure of non-payment, and therefore, have a credit requirement. SPP will establish a Total TCR Credit Requirement for each Credit Customer holding TCRs or participating in a TCR Auction. A Credit Customer may satisfy its Total TCR Credit Requirement by providing Financial Security. Unsecured Credit is not available to support a Credit Customer’s holding of TCRs or activity in TCR Auctions. Additionally, SPP’s prior approval is required for a Credit Customer to acquire or transfer TCRs through bilateral transactions.

5A.1.2 To establish the credit requirement associated with TCRs, SPP analyzes: (i) the TCRs the Credit Customer holds; (ii) the Credit Customer’s Bids and Offers for TCRs in the TCR Auctions; (iii) TCR payments or charges for which settlement has been calculated but not yet invoiced; and (iv) TCR payments or charges for which an invoice has been issued but payment has not occurred.

(a) SPP calculates the potential exposure associated with the full portfolio of TCRs that are held by the Credit Customer, including TCRs obtained from LTCRs.

(b) SPP evaluates individually each TCR Bid in the TCR Auctions to ensure that the Credit Customer has sufficient Financial Security to cover the credit requirements to purchase and hold the TCR. Only the TCR Bids for which the Credit Customer has sufficient Financial Security will be credit approved for consideration in the TCR Auction.

(c) SPP evaluates individually each TCR Offer in the TCR Auctions to ensure that the Credit Customer has sufficient Financial Security to cover any credit requirements associated with the Offer and the credit requirements for the retained TCR portfolio that would result if the TCR Offer clears in the TCR Auction. Only the TCR Offers for which the Credit Customer has sufficient Financial Security will be credit approved for consideration in the TCR Auction.
Additionally, SPP analyzes the credit requirements associated with TCRs that are the subject of a proposed bilateral transfer prior to providing approval of such transfers. SPP approval of a bilateral transfer for TCRs is required for such bilateral transfers to be completed.

5A.1.3 As part of the determination of the credit requirement associated with TCRs, SPP calculates the Estimated TCR Exposure (ETCRE), which is an estimate of the potential value of the TCR over the life of the TCR. In the case of a TCR associated with a LTCR, the life of the TCR shall be considered one year. It will be calculated for all TCRs the Credit Customer holds, the Credit Customer’s TCR Bids and TCR Offers, proposed TCR bilateral transfers, and TCRs acquired through ARR self-conversion. SPP will determine the credit requirement associated with TCRs and whether the Credit Customer has available Financial Security to support its TCR activity. After the close of a TCR Auction and on an ongoing basis, SPP will update the Credit Customer’s Total TCR Credit Requirement associated with TCRs to reflect the actual TCRs the Credit Customer holds and TCR Auction results, including the costs to acquire or sell TCRs in a TCR Auction.

5A.1.4 This Article addresses the calculation of the Total TCR Credit Requirement associated with TCRs, including the ETCRE calculations for the TCRs the Credit Customer holds and the Credit Customer’s Bids and Offers for TCRs in the TCR Auctions and the acquisition and disposal costs of the TCR in the TCR Auctions; as well as the TCR payments or charges for which settlement has been calculated but not yet invoiced; and the TCR payments or charges for which an invoice has been issued but payment has not occurred. This Article also addresses the determination whether a Credit Customer has sufficient Financial Security available for the Credit Customer’s proposed TCR Auction activity or proposed bilateral transfers of TCRs.

Proposed Criteria Language Revision

N/A
# PRR Impact Analysis Report

<table>
<thead>
<tr>
<th>PRR Number</th>
<th>Marketplace-PRR138</th>
<th>PRR Title</th>
<th>Long Term Congestion Rights</th>
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<tr>
<td>Impact Analysis Date</td>
<td>9/13/2013</td>
<td>Estimated Cost Impact</td>
<td>$5.5M</td>
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<tr>
<td>Estimated Project Time Requirements</td>
<td>TBD</td>
<td>Requirements</td>
<td>Current staff estimate is 19 months.</td>
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<tr>
<td>SPP Applications Impacted</td>
<td>Check off the systems that are (or may be) impacted.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Include a short explanation as to why each application is (or might be) affected in this area.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Nexant Software: New evaluation process to give LSEs priority and respect previously awarded LTCRs will have to be developed that is different than any other approach Nexant uses.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Credit Management System (CMS): Potential changes to the TCR estimated exposure calculation.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Centralized Modeling Tool (CMT): More and potentially different Settlement Locations will be needed.</td>
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</table>
## PRR Impact Analysis Report

### SPP Long-Term Staffing Impacts

<table>
<thead>
<tr>
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<th>IT</th>
<th>Settlements</th>
<th>Other</th>
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<tbody>
<tr>
<td>Operations</td>
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<td></td>
<td></td>
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</table>

Additional staff required:  
- Yes
- No

Detail each group separately:

### Members Software Systems/Processes Impacted

<table>
<thead>
<tr>
<th>Software Systems/Processes Impacted</th>
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<tbody>
<tr>
<td>ICCP</td>
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<td>MUI</td>
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<td>OPS1 Reports</td>
</tr>
<tr>
<td>RTO_SS</td>
</tr>
<tr>
<td>TCR API</td>
</tr>
</tbody>
</table>

Check off the software systems that are (or may be) impacted.

Include a short explanation as to why each application is (or might be) affected in this area.

TCR API: MPs will be submitting additional information related to the Long Term Congestion Rights.

Member Processes Impacted:
MPs will participate in a new LTCR allocation process and will need to perform evaluations related to the new process.

### Evaluation of Interim Solutions (e.g., manual workarounds)

N/A

### Comments
Modifications were made to the TCR Markets processes to incorporate the addition of Long Term Congestion Rights.

In the October, 2013 FERC Order approving the Integrated Marketplace Filing, FERC required SPP to implement Long Term Congestion Rights in compliance with FERC Order 681 180 days following Integrated Marketplace go-live. This MPRR is meant to comply with FERC’s directive.
<table>
<thead>
<tr>
<th>PRR No.</th>
<th>Marketplace-PRR139</th>
<th>PRR Title</th>
<th>Revenue Neutrality Correction</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Timeline**

- **Normal**
- **Expedited**
- **Urgent Action**

Provide explanation if Expedited and/or Urgent Action is selected: This MPRR is Expedited to go to the October MOPC.

**Recommendation Action**

- **Approve**
- **Reject**
- **Require additional information**
- **Defer**
- **Refer**

**Impact Analysis Required**

- **Yes – If yes, estimated cost:**
- **No**

SPP Staff will complete this section.

**Protocol Section(s) Requiring Revision**

- **Section No.:** 4.5.12; 4.5.8.18; 4.5.10.6
- **Title:** Revenue neutrality Uplift Distribution Amount; Transmission Congestion Rights Annual Closeout Amount; Auction Revenue Rights Annual Closeout Amount
- **Protocol Version:** 15.0a

**Type of Revision**

- **Correction/Clean-Up**
- **Clarification**
- **Design Enhancement**
- **Design Change**

**Timeline**

- **Go-Live**
- **Post Go-Live**

**Revision Description**

This MPRR clarifies that when non-divisible (residual) amounts remain after performing normal distributions, in order to remain revenue neutral, SPP will sum the residual amounts annually and allocate these amounts back per Asset Owner. The following amounts (credits or charges) will be allocated in this way: Revenue Neutrality uplift distribution amount, TCR annual closeout amount, and ARR allocation annual closeout amount

The equation for Revenue Neutrality Uplift Distribution Amount does not correctly reflect what is coded. These formulas were updated in MCRR35. The absolute value function is not in the correct position. This MPRR changes the formulas to correct them. No system changes are needed since it is already coded correctly.

**Tariff Implications or Changes**

- **Yes – Section No:** *(Include a summary of impact and/or specific changes)*

Attachments AE Section 8.5.15: Transmission Congestion Rights Annual Closeout Amount; 8.7.6: Auction Revenue Rights Annual Closeout Amount; 8.8: Revenue Neutrality Uplift Distribution Amount

- **No**

**Criteria Impact or Changes**

- **Yes – Section No:** *(Include a summary of impact and/or specific changes)*

- **No**
4.5.12 Revenue Neutrality Uplift Distribution Amount

(1) A charge or credit will be calculated at each Settlement Location for each Asset Owner for each hour in order for SPP to remain revenue neutral. Contributors to revenue non-neutrality include:

(a) Rounding errors (related to the calculation of all Charges/Credits);
(b) Inadvertent Interchange (as calculated as shown in equation b.3 below);
(c) Joint Operating Agreement Charges/Credits;
(d) RTBM congestion (as calculated as shown in equation b.4 below);
(e) RTBM Regulation Deployment Adjustment;
(f) Make-Whole payments for Out-of-Merit Energy; and
(g) Miscellaneous Charges/Credits.

The amount will be determined by multiplying the Asset Owner hourly determinant by a daily Revenue Neutrality Uplift (RNU) rate. The Asset Owner hourly determinant is equal to the sum that Asset Owner’s actual generation MWh, actual load MWh, actual...
Interchange Transaction MWh, DA Market cleared Virtual Offer MWh and DA Market cleared Virtual Bid MWh for the Hour, where all of these values are assumed to be positive values.

The calculation of the Revenue Neutrality Uplift (RNU) for each Asset Owner and Settlement Location in the SPP footprint can result in residual amounts due to rounding. The sum of the residual amounts due to rounding can result in SPP not being revenue neutral for the Operating Day. The residual amounts for each Operating Day will be summed on a yearly basis. The annual residual amount, whether a credit or a charge, will be uplifted to the Asset Owners and Settlement Locations. On Operating Day March 1 of every year, SPP will uplift the annual residual amount with a Miscellaneous Adjustment to the Asset Owners and Settlement Locations.

The amount to each applicable Asset Owner is calculated as follows.

$$\#\text{RtRnuHrlyAmt}_{a,s,h} = (\text{RtRnuSppDistRate}_{d} \times \text{RtRnuDistHrlyQty}_{a,s,h}) \times (-1)$$

Where,

(a) $$\#\text{RtRnuDistHrlyQty}_{a,s,h} = \text{ABS} \left(\sum_{i} \text{ABS} (\text{RtBillMtr5minQty}_{a,s,i}) / 12\right) + \text{ABS} \left(\sum_{i} \sum_{t} \left[ \text{ABS} (\text{RtImpExp5minQty}_{a,s,i,t}) / 12 \right] \times (1 - \text{RsgCrdFlg}_{t}) \right) + \text{ABS} \left(\sum_{t} \text{ABS} (\text{DaClrdVHrlyQty}_{a,s,h,t})\right)$$

(MCRR35.1]

(b)$$\#\text{RtRnuSppDistRate}_{d} = \left(\text{DaRevInadqcSppAmt}_{spp,d} + \text{RtRevInadqcSppAmt}_{spp,d} \right) + \text{RtOomSppAmt}_{spp,d} + \text{RtRegAdjSppAmt}_{spp,d} + \text{RtJoaSppAmt}_{spp,d} - \text{RtNetInadvertentSppAmt}_{spp,d} + \text{RtCongestionSppAmt}_{spp,d} / \text{RtRnuDistSppQty}_{spp,d}$$

Where,
\[ \text{RtOomSppAmt}_{spp,d} = \sum_{m} \text{RtOomMpAmt}_{m,d} \]

\[ \text{RtRegAdjSppAmt}_{spp,d} = \sum_{m} \text{RtRegAdjMpAmt}_{m,d} \]

\[ \text{RtJoaSppAmt}_{spp,d} = \sum_{a} \sum_{h} \sum_{f} \text{RtJoaHrlyAmt}_{a,h,f} \]

\[ \text{RtRnuDistSppQty}_{spp,d} = \sum_{a} \sum_{s} \sum_{h} \text{RtRnuDistHrlyQty}_{a,s,h} \]

\[ (b.1) \quad \text{DaRevInadqcSppAmt}_{spp,d} = \]

\[ \sum_{m} \left( \text{DaEnergyMpAmt}_{m,d} + \text{DaNEnergyMpAmt}_{m,d} + \text{DaVEnergyMpAmt}_{m,d} + \text{DaRegUpMpAmt}_{m,d} + \text{DaSpinMpAmt}_{m,d} + \text{DaSuppMpAmt}_{m,d} + \text{DaRegDnMpAmt}_{m,d} + \text{DaRegUpDistMpAmt}_{m,d} + \text{DaSpinDistMpAmt}_{m,d} + \text{DaSuppDistMpAmt}_{m,d} + \text{DaRegDnDistMpAmt}_{m,d} + \text{DaMwpMpAmt}_{m,d} + \text{TcrFundMpAmt}_{m,d} + \text{TcrUpliftDlyMpAmt}_{m,d} + \text{DaOclDistMpAmt}_{m,d} + \text{TcrAucTxnMpAmt}_{m,d} + \text{ArrAucTxnMpAmt}_{m,d} + \text{ArrUpliftMpAmt}_{m,d} + \text{DaDRMpAmt}_{m,d} + \text{DaDRDistMpAmt}_{m,d} \right) \]

\[ - \text{ECFDlyAmt}_{d} - \text{ARFDlyAmt}_{d} \]

\[ (b.2) \quad \text{RtRevInadqcSppAmt}_{spp,d} = \]

\[ \sum_{m} \left( \text{RtEnergyMpAmt}_{m,d} + \text{RtNEnergyMpAmt}_{m,d} + \text{RtVEnergyMpAmt}_{m,d} \right) \]
+ RtRegUpMpAmt_{m,d} + RtRegDnMpAmt_{m,d} + RtSpinMpAmt_{m,d} \\
+ RtSuppMpAmt_{m,d} + RtMwpMpAmt_{m,d} \\
+ RtMwpDistMpAmt_{m,d} + RtRegNonPerfMpAmt_{m,d} \\
+ RtRegNonPerfDistMpAmt_{m,d} + RtCRDeplFailMpAmt_{m,d} \\
+ RtOclDistMpAmt_{m,d} + RtCRDeplFailDistMpAmt_{m,d} \\
+ RtRegUpDistMpAmt_{m,d} + RtRegDnDistMpAmt_{m,d} \\
+ RtSpinDistMpAmt_{m,d} + RtSuppDistMpAmt_{m,d} \\
+ RtRsgDistMpAmt_{m,d} + RtRsgDlyAmt_{a,d} \\
+ \sum_i \text{RtRsgDlyAmt}_{a,d} \\
+ \sum_i \sum_a \sum_c \sum_s \{ \text{IF rnu} = 1, \text{THEN MiscDlyAmt}_{a,c,s,rnu,d}, \text{ELSE 0} \} + \\
\text{RtNetInadvertentSppAmt}_{spp,d} \\
- \text{RtCongestionSppAmt}_{spp,d} \\

(b.3) \quad \text{RtNetInadvertentSppAmt}_{spp,d} = \sum_i \text{RtNetInadvertentSpp5minAmt}_{i} \\

(b.3.1) \quad \#\text{RtNetInadvertentSpp5minAmt}_{i} = \\
\left( \left( \text{RtNetActIntrchngSpp5minQty}_{i} - \text{RtNetSchIntrchngSpp5minQty}_{i} \right) \right) \times \text{RtMec5minPrc}_{i} / 12 \\

(b.4) \quad \#\text{RtCongestionSppAmt}_{spp,d} = \\
\sum_a \sum_s \sum_i \left( \left( \left( \text{RtBillMtr5minQty}_{a,s,i} - \text{DaClrdHrlyQty}_{a,s,h} \right) \right) \right)
\[ + \sum_{i} (RtImpExp5MinQty_{a,s,i,t} - DaImpExp5MinQty_{a,s,i,t}) \]

\[ - \sum_{i} DaClrdVHrlyQty_{a,s,h,r} \times RtMcc5minPrc_{s,i} / 12 \]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

\[ RtRnuDlyAmt_{a,s,d} = \sum_{h} RtRnuHrlyAmt_{a,s,h} \]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ RtRnuAoAmt_{a,m,d} = \sum_{s} RtRnuDlyAmt_{a,s,d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ RtRnuMpAmt_{m,d} = \sum_{a} RtRnuAoAmt_{a,m,d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtRnuHrlyAmt(_{a,s,h})</td>
<td>$</td>
<td>Hour</td>
<td><em>Real-Time Revenue Neutrality Uplift Amount per AO per Settlement Location per Hour</em> – The amount for revenue neutrality to AO (a) at Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
<td>RtRnuSppDistRate(_d)</td>
<td>$/MW</td>
<td>Operating Day</td>
<td><em>Real-Time Revenue Neutrality Uplift SPP Distribution Rate per Operating Day</em> – The rate applied to AO (a)’s (RtRnuDistHrlyQty(_{a,s,h}) in each Hour (h) at Settlement Location (s) in Operating Day (d).</td>
</tr>
<tr>
<td>RtRnuDistHrlyQty(_{a,s,h})</td>
<td>MWh</td>
<td>Hour</td>
<td><em>Real-Time Revenue Neutrality Uplift Quantity per AO per Hour per Settlement Location</em> – The total MWh RNU allocation determinant for AO (a) at Settlement Location (s) for Hour (h).</td>
</tr>
<tr>
<td>RtRnuDistSppQty(_{spp,d})</td>
<td>MWh</td>
<td>Operating Day</td>
<td><em>Real-Time Revenue Neutrality Uplift Quantity for SPP per Operating Day</em> – The total MWh RNU allocation determinant for SPP on a system-wide basis.</td>
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<tr>
<td>DaClrdVHrlyQty(_{a,s,h,t})</td>
<td>MWh</td>
<td>Hour</td>
<td><em>Day-Ahead Cleared Virtual Energy Quantity per AO per Transaction per Settlement Location per Hour</em> – The value defined under Section 4.5.8.3.</td>
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<tr>
<td>RtOomSppAmt(_{spp,d})</td>
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<td>Operating Day</td>
<td><em>Real-Time Out-Of-Merit Make-Whole-Payment Amount for SPP per Operating Day</em> – The SPP system-wide total of the values described under Section 4.5.9.9.</td>
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<td>RtRegAdjSppAmt(_{spp,d})</td>
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<td>Operating Day</td>
<td><em>Real-Time Regulation Deployment Adjustment Amount for SPP per Operating Day</em> – The SPP system-wide total of the values described under Section 4.5.9.18.</td>
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<td>RtJoaSppAmt(_{spp,d})</td>
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<td><em>Real-Time Joint Operating Agreement Amount for SPP per Operating Day</em> – The SPP system-wide total of the values calculated under Section 4.5.9.21.</td>
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<td>Operating Day</td>
<td><em>Day-Ahead Revenue Inadequacy Amount</em> – The amount of mismatch on an SPP-wide basis between total DA Market charges and DA Market credits for Operating Day (d).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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<td>------</td>
<td>---------------------</td>
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</tr>
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<td>DaEnergyMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
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<td>Operating Day</td>
<td>Day-Ahead Asset Energy Amount per MP per Operating Day – The value calculated under Section 4.5.8.1.</td>
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<td>Day-Ahead Non-Asset Energy Amount per MP per Operating Day – The value calculated under Section 4.5.8.2.</td>
</tr>
<tr>
<td>DaVEnergyMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Virtual Energy Amount per MP per Operating Day – The value calculated under Section 4.5.8.3.</td>
</tr>
<tr>
<td>DaRegUpMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Up Amount per MP per Operating Day – The value calculated under Section 4.5.8.4.</td>
</tr>
<tr>
<td>DaRegDnMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Down Amount per MP per Operating Day – The value calculated under Section 4.5.8.5.</td>
</tr>
<tr>
<td>DaSpinMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Spinning Reserve Amount per MP per Operating Day – The value calculated under Section 4.5.8.6.</td>
</tr>
<tr>
<td>DaSuppMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Supplemental Reserve Amount per MP per Operating Day – The value calculated under Section 4.5.8.7.</td>
</tr>
<tr>
<td>DaRegUpDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Up Distribution Amount per MP per Operating Day – The value calculated under Section 4.5.8.8.</td>
</tr>
<tr>
<td>DaRegDnDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Down Distribution Amount per MP per Operating Day – The value calculated under Section 4.5.8.9.</td>
</tr>
<tr>
<td>DaSpinDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Spinning Reserve Distribution Amount per MP per Operating Day – The value calculated under Section 4.5.8.10.</td>
</tr>
<tr>
<td>DaSuppDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Supplemental Reserve Distribution Amount per MP per Operating Day – The value calculated under Section 4.5.8.11.</td>
</tr>
<tr>
<td>DaMwpMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Amount per MP per Operating Day – The value calculated under Section 4.5.8.12.</td>
</tr>
<tr>
<td>DaMwpDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Distribution Amount per MP per Operating Day – The value calculated under Section 4.5.8.13.</td>
</tr>
<tr>
<td>TcrFundMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Rights Funding Amount per MP per Operating Day – The value calculated under Section 4.5.8.14.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------</td>
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<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>TcrUpliftDlyMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Transmission Congestion Rights Uplift Amount per MP per Operating Day</em> – The value calculated under Section 4.5.8.15.</td>
</tr>
<tr>
<td>ECFDlyAmt&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Excess Congestion Fund Amount per Operating Day</em> – The value calculated under Section 4.5.8.16.</td>
</tr>
<tr>
<td>ARFDlyAmt&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Fund Amount per Operating Day</em> – The value calculated under Section 4.5.10.4.</td>
</tr>
<tr>
<td>DaOclDistMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Day-Ahead Over Collected Losses Distribution Amount per MP per Operating Day</em> – The value calculated under Section 4.5.8.19.</td>
</tr>
<tr>
<td>TcrAucTxnMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Transmission Congestion Right Auction Daily Amount per MP per Operating Day</em> – The value calculated under Section 4.5.10.1.</td>
</tr>
<tr>
<td>ArrAucTxnMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Rights Funding Amount per Operating Day</em> – The value calculated under Section 4.5.10.2.</td>
</tr>
<tr>
<td>ArrUpliftMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Rights Funding Uplift Amount per MP per Operating Day</em> – The value calculated under Section 4.5.10.3.</td>
</tr>
<tr>
<td>DaDRMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Day-Ahead Demand Reduction Amount per Market Participant per Operating Day</em> – The value calculated under Section 4.5.9.24[M1PRR77.4]</td>
</tr>
<tr>
<td>DaDRDistMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Day-Ahead Demand Reduction Distribution Amount per Market Participant per Operating Day</em> – The value calculated under Section 4.5.9.25[M1PRR77.5]</td>
</tr>
<tr>
<td>RtRevInadqcSppAmt&lt;sub&gt;spp,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Real-Time Revenue Inadequacy Amount</em> – The amount of mismatch on an SPP-wide basis between total RTBM charges and RTBM credits.</td>
</tr>
<tr>
<td>RtBillMtr5minQty&lt;sub&gt;a,s,i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval</em> - The value described under Section 4.5.9.1.</td>
</tr>
<tr>
<td>RtImpExp5minQty&lt;sub&gt;a,s,i,t&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval per Transaction</em> – The value described under Section 4.5.9.2.</td>
</tr>
<tr>
<td>RsgCrdFlg&lt;sub&gt;r&lt;/sub&gt;, (Not Available on Settlement)</td>
<td>none</td>
<td>none</td>
<td><em>Reserve Sharing Group Contingency Reserve Deployment Flag per Event</em> – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Statement)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DaClrdVHrlyQty (_{a, s, h, t})</td>
<td>MWh</td>
<td>Hour</td>
<td><strong>Day-Ahead Virtual Energy Quantity per AO per Settlement Location per Hour per Transaction</strong> – The value described under Section 4.5.8.3.</td>
</tr>
<tr>
<td>DaClrdHrlyQty (_{a, s, h})</td>
<td>MWh</td>
<td>Hour</td>
<td><strong>Day-Ahead Asset Energy Quantity per AO per Settlement Location per Hour</strong> – The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>DaImpExp5MinQty (_{a, s, i, t})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Day-Ahead Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval per Transaction</strong> – The value described under Section 4.5.8.2.</td>
</tr>
<tr>
<td>RtMcc5minPrc (_{s, i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Marginal Congestion Component of Real-Time LMP</strong> – The Marginal Congestion Component of the Real-Time LMP at Settlement Location (_s) for Dispatch Interval (_i).**</td>
</tr>
<tr>
<td>RtEnergyMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Energy Amount per MP per Operating Day</strong> – The value described under Section 4.5.9.1.</td>
</tr>
<tr>
<td>RtNEnergyMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Non-Asset Energy Amount per MP per Operating Day</strong> – The value described under Section 4.5.9.2.</td>
</tr>
<tr>
<td>RtVEnergyMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Virtual Energy Amount per MP per Operating Day</strong> – The value described under Section 4.5.9.3.</td>
</tr>
<tr>
<td>RtRegUpMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Regulation-Up Amount per MP per Operating Day</strong> – The value described under Section 4.5.9.4.</td>
</tr>
<tr>
<td>RtRegDnMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Regulation-Down Amount per MP per Operating Day</strong> – The value described under Section 4.5.9.5.</td>
</tr>
<tr>
<td>RtSpinMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Spinning Reserve Amount per MP per Operating Day</strong> – The value described under Section 4.5.9.6.</td>
</tr>
<tr>
<td>RtSuppMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Supplemental Reserve Amount per MP per Operating Day</strong> – The value described under Section 4.5.9.7.</td>
</tr>
<tr>
<td>RtMwpMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>RUC Make-Whole-Payment Amount per MP per Operating Day</strong> – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>RtOomMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Out-Of-Merit Make-Whole-Payment Amount per MP per Operating Day</strong> - The value described under Section 4.5.9.9.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------------</td>
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<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtMwpDistMpAmt (_m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Distribution Amount per MP per Operating Day – The value described under Section 4.5.9.10.</td>
</tr>
<tr>
<td>RtRegNonPerfMpAmt (_m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation Non-Performance Amount per MP per Operating Day – The value described under Section 4.5.9.15.</td>
</tr>
<tr>
<td>RtCRDeplFailMpAmt (_m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Contingency Reserve Deployment Failure Amount per MP per Operating Day – The value described under Section 4.5.9.17.</td>
</tr>
<tr>
<td>RtRegAdjMpAmt (_m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation Deployment Adjustment Amount per MP per Operating Day - The value described under Section 4.5.9.19.</td>
</tr>
<tr>
<td>RtOclDistMpAmt (_m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Over Collected Losses Distribution Amount per MP per Operating Day - The value calculated under Section 4.5.9.20.</td>
</tr>
<tr>
<td>RtNetInadvertentSpp5minAmt (_i)</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time SPP Inadvertent Energy Amount per Dispatch Interval – SPP net Inadvertent Energy for Dispatch Interval (_i) valued at the Real-Time LMP MEC.</td>
</tr>
<tr>
<td>RtNetInadvertentSppAmt (_spp, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time SPP Inadvertent Energy Amount per Operating Day – The sum of (\text{RtNetInadvertentSpp5minAmt}_i) for Operating Day (_d).</td>
</tr>
<tr>
<td>RtCongestionSppAmt (_spp, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time SPP Net Congestion Revenue Amount – The net amount of total Real-Time congestion revenue collected over Operating Day (_d).</td>
</tr>
<tr>
<td>RtNetActIntrchngSpp5minQty (_i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time SPP Net Actual Interchange per Dispatch Interval – SPP Net Actual Interchange in Dispatch Interval (_i).</td>
</tr>
<tr>
<td>RtNetSchIntrchngSpp5minQty (_i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time SPP Net Scheduled Interchange per Dispatch Interval – SPP Net Actual Interchange in Dispatch Interval (_i).</td>
</tr>
<tr>
<td>RtMec5minPrc (_i)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Marginal Energy Component of Real-Time LMP per Dispatch Interval – The Real-Time LMP MEC in Dispatch Interval (_i).</td>
</tr>
<tr>
<td>RtJoaHrlyAmt (_a, h, f)</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Joint Operating Agreement Hourly Amount - The value calculated under Section 4.5.9.21.</td>
</tr>
<tr>
<td>RtRegNonPerfDistMpAmt (_m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation Non-Performance Distribution Amount - The value calculated under Section 4.5.9.16.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtCRDeplFailDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Contingency Reserve Deployment Failure Distribution Amount - The value calculated under Section 4.5.9.18.</td>
</tr>
<tr>
<td>RtRegUpDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation-Up Distribution Amount – The value calculated under Section 4.5.9.11.</td>
</tr>
<tr>
<td>RtRegDnDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation-Down Distribution Amount – The value calculated under Section 4.5.9.12.</td>
</tr>
<tr>
<td>RtSpinDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Spinning Reserve Distribution Amount – The value calculated under Section 4.5.9.13.</td>
</tr>
<tr>
<td>RtSuppDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Supplemental Reserve Distribution Amount – The value calculated under Section 4.5.9.14.</td>
</tr>
<tr>
<td>RtRsgDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Reserve Sharing Group Distribution Amount – The amount calculated under Section 4.5.9.23.</td>
</tr>
<tr>
<td>RtDRMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Demand Reduction Amount per Market Participant per Operating Day – The amount calculated under Section 4.5.8.22 [MPRR77.6]</td>
</tr>
<tr>
<td>RtDRDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Demand Reduction Distribution Amount per Market Participant per Operating Day – The amount calculated under Section 4.5.8.22 [MPRR77.7]</td>
</tr>
<tr>
<td>RtRsgDlyAmt&lt;sub&gt;a, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Reserve Sharing Group Amount – The amount calculated under Section 4.5.9.22.</td>
</tr>
<tr>
<td>MiscDlyAmt&lt;sub&gt;a,c,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Miscellaneous Amount per AO per Charge Type per Operating Day – The miscellaneous amount to AO a for charge type c in Operating Day d as described under Section 4.5.10.4.</td>
</tr>
<tr>
<td>RtRnuDlyAmt&lt;sub&gt;a,s,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Revenue Neutrality Uplift Amount per AO per Settlement Location per Operating Day – The amount for revenue neutrality to AO a at Settlement Location s in Operating Day d.</td>
</tr>
<tr>
<td>RtRnuAoAmt&lt;sub&gt;a,m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Revenue Neutrality Uplift Amount per AO per Operating Day – The amount for revenue neutrality to AO a associated with Market Participant m in Operating Day d.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------</td>
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<td>---------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>$\text{RtRnuMpAmt}_{m,d}$</td>
<td>$\text{$}$</td>
<td>Operating Day</td>
<td><em>Real-Time Revenue Neutrality Uplift Amount per MP per Operating Day</em> – The amount for revenue neutrality to MP $m$ in Operating Day $d$.</td>
</tr>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>$s$</td>
<td>none</td>
<td>none</td>
<td>A Resource Settlement Location.</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$i$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Bilateral Settlement Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$f$</td>
<td>none</td>
<td>none</td>
<td>A flowgate identified in the applicable JOA.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$\text{rnu}$</td>
<td>none</td>
<td>none</td>
<td>A flag which instructs the settlement system to include the amount in Revenue Neutrality Uplift calculations ($1 = Y$, $0 = N$).</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.18 Transmission Congestion Rights Annual Closeout Amount

(1) A DA Market annual credit or charge\(^1\) will be calculated for each Asset Owner Transmission Customer with ARR Nomination Caps established under Section 5.1.3 to the extent that there are any funds remaining once all credits are paid under Section 4.5.8.17. **The calculation of the Transmission Congestion Rights Annual Closeout Amount for each Asset Owner with an ARR nomination Cap can result in residual amounts due to rounding.** The sum of the residual amounts due to rounding across Asset Owners can result in the Transmission Congestion Rights not being revenue neutral for the year. The difference, whether a credit or charge, will be uplifted to the Asset Owners on a yearly basis. On Operating Day March 1, of every year, SPP will uplift the annual residual amount with a Miscellaneous Adjustment to the Asset Owners. **The Transmission Congestion Rights Annual Closeout amount is calculated as follows:**

\[
#\text{TcrCloseoutYrlyAmt}_{a, yr} = (-1) \times \left[ \text{ECFYrlyAmt}_{yr} + \text{TcrPaybackSppYrlyAmt}_{yr} \right] 
\]

\[
\times \text{ArrNominationCapAoYrlyQty}_{a, yr} 
\]

\[
/ \text{ArrNominationCapSppYrlyQty}_{yr} 
\]

(a) \text{TcrPaybackSppYrlyAmt}_{yr} = \sum_a \text{TcrPaybackYrlyAmt}_{a, yr}

(b) \text{ArrNominationCapAoYrlyQty}_{a, yr} = \sum_d \text{ArrNominationCapQty}_{a, d}

(c) \text{ArrNominationCapSppYrlyQty}_{yr} = \sum_a \sum_d \text{ArrNominationCapQty}_{a, d}

(2) For each Market Participant, an annual amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The annual amount is calculated as follows:

\[
\text{TcrCloseoutYrlyMpAmt}_{m, yr} = \sum_a \text{TcrCloseoutYrlyAmt}_{a, yr} 
\]

\(^1\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>TcrCloseoutYrlyAmt&lt;sub&gt;a, yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Annual Payback Amount per AO - AO a’s share of any remaining $ECFYrlyAmt&lt;sub&gt;mn&lt;/sub&gt; in year yr.</td>
</tr>
<tr>
<td>TcrPaybackYrlyAmt&lt;sub&gt;a, yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Annual Payback Amount per AO - The value calculated under Section 4.5.8.17.</td>
</tr>
<tr>
<td>TcrPaybackSppYrlyAmt&lt;sub&gt;yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Payback Total per Year - The SPP total of the values calculated under Section 4.5.8.17 for year yr.</td>
</tr>
<tr>
<td>ArrNominationCapAoYrlyQty&lt;sub&gt;a, yr&lt;/sub&gt;</td>
<td>MW</td>
<td>Year</td>
<td>ARR Nomination Cap per AO per Year – The sum of $ArrNominationCapQty for AO a for year yr.</td>
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<tr>
<td>ArrNominationCapSppYrlyQty&lt;sub&gt;yr&lt;/sub&gt;</td>
<td>MW</td>
<td>Year</td>
<td>ARR Nomination Cap Total per Year – The SPP total of $ArrNominationCapQty for year yr.</td>
</tr>
<tr>
<td>ECFYrlyAmt&lt;sub&gt;yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Excess Congestion Fund Yearly Amount – The sum of $ECFMthlyAmt&lt;sub&gt;mn&lt;/sub&gt; in year yr.</td>
</tr>
<tr>
<td>ArrNominationCapQty&lt;sub&gt;a, d&lt;/sub&gt;</td>
<td>MW</td>
<td>Operating Day</td>
<td>ARR Nomination Cap per AO per Operating Day – AO a’s Arr Nomination Maximum Daily Quantity that an Eligible Entity qualifies for as described under Section 5.1.3 ARR Nomination Cap.</td>
</tr>
<tr>
<td>TcrCloseoutYrlyMpAmt&lt;sub&gt;m, yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Annual Payback Amount per MP per Year - MP a’s share of the $ECFYrlyAmt&lt;sub&gt;yr&lt;/sub&gt; in year yr.</td>
</tr>
</tbody>
</table>

| a                               | none | none                | An Asset Owner.                                                             |
| d                               | none | none                | An Operating Day.                                                          |
| yr                              | none | none                | A year.                                                                    |
| m                               | none | none                | A Market Participant.                                                      |
4.5.10.6 Auction Revenue Rights Annual Closeout Amount

An annual credit or charge\(^2\) will be calculated for each Asset Owner with ARR Nomination Caps established under Section 5.1.3 to the extent that there are any funds remaining once all credits are paid under Section 4.5.10.4. The calculation for the Auction Revenue Rights Annual Closeout Amount for each Asset Owner with an ARR Nomination Cap can result in residual amounts due to rounding. The sum of the residual amounts due to rounding across Asset Owners can result in the Auction Revenue Rights not being revenue neutral for the year. The difference, whether a credit or charge, will be uplifted to the Asset Owners on a yearly basis. On Operating Day March 1, of every year, SPP will uplift the annual residual amount with a Miscellaneous Adjustment to the Asset Owners. The Auction Revenue Rights Annual Closeout amount is calculated as follows:

\[ \text{#ArrCloseoutYrlyAmt}_{a, yr} = (-1) \times [\text{ARFYrlyAmt}_{yr} + \text{ArrPaybackSppYrlyAmt}_{yr}] \]

* \([\text{ArrNominationCapAoYrlyQty}_{a, yr} / \text{ArrNominationCapSppYrlyQty}_{yr}]\)

Where,

\[ \text{ArrPaybackSppYrlyAmt}_{yr} = \sum_{a} \text{ArrPaybackYrlyAmt}_{a, yr} \]

For each Market Participant, an annual amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The annual amount is calculated as follows:

\[ \text{ArrCloseoutYrlyMpAmt}_{m, yr} = \sum_{a} \text{ArrCloseoutYrlyAmt}_{a, yr} \]

\(^2\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>ArrCloseoutYrlyAmt (a, yr)</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Rights Annual Payback Amount per AO per Year - AO (a)’s share of any remaining ARFYrlyAmt (mn) in year (yr).</td>
</tr>
<tr>
<td>ArrPaybackYrlyAmt (a, yr)</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Rights Annual Payback Amount per AO per Year - The value calculated under Section 4.5.8.17.</td>
</tr>
<tr>
<td>ArrNominationCapAoYrlyQty (a, yr)</td>
<td>MW</td>
<td>Year</td>
<td>ARR Nomination Cap per AO per Year – The sum of the values described under Section 4.5.8.18 for AO (a) for year (yr).</td>
</tr>
<tr>
<td>ArrNominationCapSppYrlyQty (yr)</td>
<td>MW</td>
<td>Year</td>
<td>ARR Nomination Cap Total per Year – The value calculated under Section 4.5.8.18.</td>
</tr>
<tr>
<td>ArrPaybackSppYrlyAmt (yr)</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Rights Annual Payback Amount per Year - The value calculated under Section 4.5.8.18.</td>
</tr>
<tr>
<td>ARFYrlyAmt (yr)</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Fund Yearly Amount – The sum of ARFMthlyAmt (mn) in year (yr).</td>
</tr>
<tr>
<td>ArrNominationCapQty (a, d)</td>
<td>MW</td>
<td>Operating Day</td>
<td>ARR Nomination Cap per AO per Operating Day – The value described under Section 4.5.8.18.</td>
</tr>
<tr>
<td>ArrCloseoutYrlyMpAmt (m, yr)</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Rights Annual Payback Amount per MP per Year - MP (a)’s share of the ARFYrlyAmt (yr) in year (yr).</td>
</tr>
</tbody>
</table>

\(a\), none

\(d\), none

\(yr\), none

\(m\), none

An Asset Owner.

An Operating Day.

A year.

A Market Participant.
8.5.15 Transmission Congestion Rights Annual Closeout Amount

A Day-Ahead Market annual payment will be calculated as follows for each Asset Owner with ARR Nomination Caps established under Section 7.1.3 of this Attachment AE to the extent that there are any funds remaining once all payments are made under Section 8.5.14.\footnote{The calculations below can result in residual amounts due to rounding. The Transmission Provider will uplift the annual residual amounts to all of the Asset Owners as specified in the Market Protocols.}

TCR Annual Closeout Amount =
\[
\left[ \left( \text{Excess Congestion Fund Yearly Amount} + \text{TCR Annual Payback Total} \right) \times \left( \frac{\text{Annual ARR Nomination Cap}}{\text{Total Annual ARR Nomination Cap}} \right) \right] \times (-1)
\]

1. Excess Congestion Fund Yearly Amount is equal to the value calculated under Section 8.5.14 of this Attachment.
2. TCR Annual Payback Total is equal to the sum of all payments made under Section 8.5.14.
3. An Asset Owner’s Annual ARR Nomination Cap is equal to the sum of all of that Asset Owner’s daily ARR nomination caps, as calculated under Section 7.1.3 of this Attachment AE, for the year.
4. Total Annual ARR Nomination Cap is equal to the sum of all Asset Owners’ Annual ARR Nomination Caps for the year.

8.7.6 Auction Revenue Rights Annual Closeout Amount

An annual payment will be calculated as follows for each Asset Owner with ARR Nomination Caps established under Section 7.1.3 of this Attachment AE to the extent that there are any funds remaining once all payments are made under Section 8.7.4.\footnote{The calculations below can result in residual amounts due to rounding. The Transmission Provider will uplift the annual residual amounts to all of the Asset Owners as specified in the Market Protocols.}

ARR Annual Closeout Amount =
\[
\left[ \left( \text{Excess TCR Revenue Fund Yearly Amount} + \text{ARR Annual Payback Total} \right) \times \left( \frac{\text{Annual ARR Nomination Cap}}{\text{Total Annual ARR Nomination Cap}} \right) \right] \times (-1)
\]
(1) Excess TCR Revenue Fund Yearly Amount is equal to the value calculated under Section 8.7.5 of this Attachment.

(2) ARR Annual Payback Total is equal to the sum of all payments made under Section 8.7.5.

(3) An Asset Owner’s Annual ARR Nomination Cap is equal to the sum of all of that Asset Owner’s daily ARR nomination caps, as calculated under Section 7.1.3 of this Attachment AE, for the year.

(4) Total Annual ARR Nomination Cap is equal to the sum of all Asset Owners’ Annual ARR Nomination Caps for the year.

8.8 Revenue Neutrality Uplift Distribution Amount

The Transmission Provider shall perform the following calculation for each hour of the Operating Day for each Asset Owner and Settlement Location to ensure that the Transmission Provider is revenue neutral in each hour of the Operating Day. The Transmission Provider shall calculate hourly summations to each Market Participant for all Asset Owners it represents and shall calculate daily summations as specified in the Market Protocols. The calculations below can result in residual amounts due to rounding. The Transmission Provider will sum up those residual amounts per Operating Day on an annual basis and will uplift the annual residual amounts to all of the Asset Owners as specified in the Market Protocols.

Revenue Neutrality Uplift Distribution Amount =
Daily RNU Distribution Rate * RNU Distribution Volume * (-1)

(1) The Daily RNU Distribution Rate is equal to the Daily RNU Distribution Amount divided by the Daily RNU Distribution Volume.

(a) The Daily RNU Distribution Amount is equal to:

(i) The sum of all Asset Owners’ charges and payments calculated under Section 8.5, excluding payments under Sections 8.5.13, 8.5.14 and 8.5.15, for the Operating Day; plus

(ii) The sum of all Asset Owners’ charges and payments calculated under Section 8.6 for the Operating Day; plus

(iii) The sum of all Asset Owners’ charges and payments calculated under Section 8.7, excluding payments under Sections 8.7.4, 8.7.5 and 8.7.6; plus
(iv) The sum of all charges and payments for emergency purchases and sales entered into by the Transmission Provider in its Balancing Authority role in order to alleviate a capacity shortage inside the SPP Balancing Authority Area or to assist an external Balancing Authority in alleviating a capacity shortage; plus

(v) Any other charges and credits not accounted for in subsections (i) through (iv) above; minus

(vi) The Excess Congestion Fund Daily Amount calculated under Section 8.5.13(3)(a) for the Operating Day; minus

(vii) The Excess TCR Revenue Fund Daily Amount calculated under Section 8.7.4(3)(a) for the Operating Day.

(b) The Daily RNU Distribution Volume is equal to the sum of all Asset Owners’ RNU Distribution Volumes for the Operating Day.

(2) An Asset Owner’s RNU Distribution Volume at a Settlement Location for an hour is equal to the sum of:

(a) The absolute value of actual metered generation or load in the hour; and

(b) The absolute value of scheduled Interchange Transactions in the hour; and

(c) The absolute value of cleared Virtual Energy Offers and Bids in the hour.

<table>
<thead>
<tr>
<th>Proposed Criteria Language Revision</th>
</tr>
</thead>
<tbody>
<tr>
<td>N/A</td>
</tr>
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</table>
PRR Recommendation Report

<table>
<thead>
<tr>
<th>PRR No.</th>
<th>Marketplace-PRR140</th>
<th>PRR Title</th>
<th>Mitigated Transition State Offers</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Timeline**
- [ ] Normal
- [x] Expedited
- [ ] Urgent Action

Provide explanation if Expedited and/or Urgent Action is selected: This MPRR is Expedited so it can go to the October MOPC.

**Recommendation Action**
- [x] Approve
- [ ] Reject
- [ ] Require additional information
- [ ] Defer
- [ ] Refer

**Impact Analysis Required**
- [ ] Yes – If yes, estimated cost: [x] No

SPP Staff will complete this section.

**Protocol Section(s) Requiring Revision**
- Section No.: Appendix G Sections; 2.4.3, 5, 5.5 (new)
- Title: Average VOM Cost, Combined Cycle (CC) Guidelines, Mitigated Transition State Offer (new)
- Protocol Version: 15.0a

**Type of Revision**
- [ ] Correction/Clean-Up
- [ ] Clarification
- [x] Design Enhancement
- [ ] Design Change

**Timeline**
- [ ] Go-Live
- [x] Post Go-Live

**Revision Description**
The changes are needed to ensure that Market Participants have the proper guidance in formulating their offers according to the combined-cycle design changes.

**Tariff Implications or Changes**
- [x] Yes – Section No: *(Include a summary of impact and/or specific changes)*

Attachment AF Section 3.4 Mitigation Measures for Transition State Offers (new)
- [ ] No

**Criteria Impact or Changes**
- [ ] Yes – Section No: *(Include a summary of impact and/or specific changes)*
- [ ] No

**MWG Review PRR Recommendation**
- **Date of Vote:** 9/10/2013
- **Vote:** Approved
- **Opposed:** N/A
- **Abstained:** AEP

**RTWG Review**
- **Date of Vote:** 9/11/2013
- **Vote:** Approved with Modifications
- **Opposed:** N/A
- **Abstained:** N/A
1.1.1 Average VOM Cost

Average VOM Cost is the average VOM cost $/mmBtu, $/MWh or $/hour. This is defined as allocated VOM dollars in the historical Maintenance Period divided by total MWhs, total fuel or total on-line hours associated with the historical Maintenance Period, depending on VOM type.

1 See Section 2.5 and Section 2.10.1.
2 See Section 2.3
3 See Section 2.7
4 See Section 2.7
The VOM adders should be reviewed and updated at least once every twelve months or once in the maintenance cycle, whichever is shorter.

If a Market Participant feels that a resource modification or required change in operating procedures will affect the resource's VOM adders, the revised VOM adders must be submitted to the SPP MMU for review and approval pursuant to the Mitigated Offer Methodology Approval Process.

5. **Combined Cycle (CC) Guidelines**

This section contains information pertaining to Combined Cycle Cost development.

**Combined Cycle** - An electric generating technology in which electricity is generated by both a combustion turbine resource (the Brayton Cycle) and a steam turbine resource (the Rankine Cycle) hence the name combined cycle. The CT exhaust heat flows to a conventional boiler or to a heat recovery steam resource (HRSG) to produce steam for use by a steam turbine resource in the production of electricity.

**Heat recovery steam resource** (HRSG) – A CT exhaust feeds hot gas into a heat to steam exchanger installed on combined-cycle power plants designed to utilize the heat in the combustion turbine exhaust to produce steam to drive a conventional steam turbine resource. The HRSG may or may not also include a supplemental source of heat, e.g duct firing.

5.1 **Heat Rate**

*Note: The information in Section 2.1 contains basic Heat Rate information relevant for all unit types including combined cycle units.*

5.2 **Performance Factors**

*Note: The information in Section 2.2 contains basic Performance Factor information relevant for all unit types including combined cycle units.*

---

5 See Section 2.6
6 See Section 2.10
5.3 Fuel Cost

*Note: The information in Section 2.3 contains basic Fuel Cost information relevant for all unit types including combined cycle units.*

5.4 Mitigated Start-Up Offer

*Note: The information in Section 2.4 contains basic Mitigated Start-Up Offer information relevant for all unit types. The following additional information only pertains to combined cycle units.*

Start costs for Combined Cycle (CC) plants shall include only the following components and shall never be less than zero:

Start cost can be calculated and offered for Hot, Intermediate and Cold Start conditions.

**Start Fuel Consumed** is the amount of fuel consumed from first CT fire to breaker closing for the steam turbine resource, as measured during a normal start sequence, and the amount of fuel consumed from breaker opening for the steam turbine resource to fuel valve closure. Additionally, for Combined Cycle Resources not registered under configuration based option, this includes the amount of fuel consumed from CT first fire to the point where heat recovery steam resource (HRSG) steam pressure matches steam turbine inlet pressure, for any CT unit/HRSG combinations started after synchronization of the steam turbine resource.

**Station service** is included from initiation of start sequence of initial combustion turbine to breaker closing of the steam turbine resource (total station use minus normal base station use) priced at the Station Service Rate.

Add to this (+) station service after breaker opening of the last component when finished operating as a combined cycle unit, priced at the Station Service rate. (Station service during shutdown should be that associated with the normal unit auxiliary equipment operated during shutdown in excess of base unit use. This station service is not to include VOM or non-normal uses.)

Minus (-) the integration of net generation from CT synchronization to steam turbine resource synchronization or to HRSG steam output at line pressure, priced at the actual cost of the unit.

Minus (-) the integration of net generation during the shutdown period, priced at the actual cost of the unit.

**Incremental labor costs** in excess of normal station manning requirements (only when necessary to start the CC unit).
Start VOM Adder - this quantity includes Start VOM $ for CT Starting from CT breaker closing to steam turbine resource breaker closing and from steam turbine resource breaker opening at the start of unit shutdown to CT breaker opening.

5.5 Mitigated Transition State Offer

Transition Fuel Consumed is the amount of additional fuel consumed moving from the current configuration to another configuration (i.e. moving from a 1 X 1 to a 2 X 1)

Incremental transition labor costs in excess of normal station manning requirements (only when necessary to transition the CC to a different configuration).

Transition VOM Cost - this quantity includes Transition VOM $ incurred moving from the current configuration to another configuration (i.e. moving from a 1 X 1 to a 2 X 1)

5.5.6 Mitigated No Load Offer

Note: The information in Section 2.7 contains basic No Load information relevant for all unit types including combined cycle units.

5.6.7 VOM Cost

Note: The information in Section 2.4 contains basic VOM Cost information relevant for all unit types. The following additional information only pertains to combined cycle units.

Combined Cycle VOM Cost – the historical VOM dollars as derived from FERC Accounts 512, 513, and 553. If submitting as a simple cycle combustion turbine, use total dollars from FERC Account 553.

5.7.8 Mitigated Spinning Reserve Offer

Note: The information in Section 2.8 contains basic Spinning Reserve information relevant for all unit types.

5.8.9 Mitigated Supplemental Reserve Offer

Note: The information in Section 2.9 contains basic Supplemental Reserve information relevant for all unit types including combined cycle units.
5.95.10 Mitigated Regulation Offers

Note: The information in Section 2.10 contains basic Regulation information relevant for all unit types including combined cycle units.

Proposed Tariff Language Revision

3.4 Mitigation Measures for Transition State Offers

The mitigation measures in this section apply only to Resources registered using the combined cycle configuration based modeling option as described in Section 4.1.2.2(4) of Attachment AE. A mitigated Transition State Offer shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines specified in the Market Protocols for each potential transition state change. The mitigated Transition State Offer may be updated up to 1100 hours on the day before the Operating Day for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Transition State Offer may be updated until the Day-Ahead RUC process begins. The mitigated Transition State Offer submitted at the time the Day-Ahead RUC process begins will apply to the Day-Ahead RUC process on the day before the Operating Day and the Intra-Day RUC processes on the Operating Day.

The Transition State Offer conduct thresholds are as follows:

(1) For Resources with local market power as described in Section 3.1(4), the conduct threshold is a 10% increase above the mitigated Transition State Offer;

(2) For all other Resources the conduct threshold is a 25% increase above the mitigated Transition State Offer.

The Transmission Provider shall apply mitigation measures by replacing the Transition State Offer with the mitigated Transition State Offer if:

(1) The Resource’s Transition State Offer exceeds the mitigated Transition State Offer by the applicable conduct threshold; and

(2) The Resource has local market power as determined in Section 3.1; and

(3) The Resource either:

(a) Fails the Market Impact Test as described in Section 3.7, or

(b) Has local market power as described in Section 3.1(4).
The mitigated Transition State Offer for a Combined-Cycle Resource shall not exceed the sum of the fuel costs incurred during the transition, additional maintenance costs incurred during the transition, and additional labor costs incurred during the transition.

The Market Participant shall submit documentation of the method for calculating the mitigated Transition State Offer that is adequate to permit the Market Monitor to verify submitted offers. Further details associated with the development of these costs are included in the Market Protocols.

Proposed Criteria Language Revision

N/A
# PRR Recommendation Report

<table>
<thead>
<tr>
<th>PRR No.</th>
<th>Marketplace-PRR141</th>
<th>PRR Title</th>
<th>Mitigated Regulation Mileage</th>
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## Timeline

- [ ] Normal
- [x] Expedited
- [ ] Urgent Action

Provide explanation if Expedited and/or Urgent Action is selected: This MPRR is Expedited so it can go to the October MOPC.

## Recommendation Action

- [x] Approve
- [ ] Reject
- [ ] Require additional information
- [ ] Defer
- [ ] Refer

## Impact Analysis Required

- [ ] Yes – If yes, estimated cost:  
- [x] No

SPP Staff will complete this section.

## Protocol Section(s) Requiring Revision

- Section No.: Appendix G Sections; 2.10, 2.10.1, 2.10.2, 2.10.3
- Title: Mitigated Regulation-Up and Regulation-Down Offers, Cost Increase due to Heat Rate increase during non-steady state, Cost increase in Variable Operations and Maintenance
- Protocol Version: 15.0a

## Type of Revision

- [ ] Correction/Clean-Up
- [ ] Clarification
- [x] Design Enhancement
- [ ] Design Change

## Timeline

- [ ] Go-Live
- [x] Post Go-Live

## Revision Description

This MPRR contains the Mitigated Offer Development Guidelines changes corresponding with MPRR 102 (Order 755 compliance). The current mitigated regulation offer components are split up into capability and mileage offers.

## Tariff Implications or Changes

- [x] Yes – Section No: (Include a summary of impact and/or specific changes)

Attachment AF Section 3.4 Mitigation Measures for Operating Reserve Offers

- [ ] No

## Criteria Impact or Changes

- [ ] Yes – Section No: (Include a summary of impact and/or specific changes)

- [x] No

## MWG Review PRR Recommendation

- **Date of Vote:** 8/21/2013  
  **Vote:** Unanimously Approved
- **Opposed:** N/A  
  **Abstained:** N/A

- **Date of Vote:** 9/17/2013  
  **Vote:** Unanimously Approved RTWG modifications
- **Opposed:** N/A  
  **Abstained:** N/A
2.10 Mitigated Regulation-Up and Regulation-Down Service Offers

The Mitigated Regulation-Up and the Mitigated Regulation-Down Offer shall include the following components up to but not exceeding:

The Mitigated Regulation-Up Mileage Offer shall include the following components up to but not exceeding:

The Mitigated Regulation-Down Mileage Offer shall include the following components up to but not exceeding:
2.10.32.10.1 Uncompensated Costs:

For Regulation-Up: Uncompensated cost should reflect the opportunity cost of the lost energy dispatch between the Maximum Economic Capacity Operating Limit and the Maximum Regulation Capacity Operating Limit or the additional cost of producing energy between the Minimum Economic Capacity Operating Limit and the Minimum Regulation Capacity Operating Limit. It shall only be included for Real-Time Balancing Market offers, and it shall not exceed the lesser of the uncompensated regulation lost opportunity cost cap, as determined by the SPP MMU, and the uncompensated cost as calculated below:

The Weighted average Mitigated Energy Offer for MW above RegMax is the area under the Mitigated Energy Offer Curve between the Maximum Regulating Capacity Operating Limit and the MW at which the DA LMP crosses the Mitigated Energy Offer Curve divided by the capacity range between the two MW points.

For Regulation-Down: Uncompensated cost should reflect the opportunity cost of the lost energy dispatch between the Maximum Economic Capacity Operating Limit and the Maximum Regulation Capacity Operating Limit or the additional cost of producing energy between the Minimum Economic Capacity Operating Limit and the Minimum Regulation Capacity Operating Limit. It shall only be included for Real-Time Balancing Market offers, and it shall not exceed the lesser of the uncompensated regulation minimum limit cost cap, as determined by the SPP MMU, and the uncompensated cost as calculated below:
The *Weighted average Mitigated Energy Offer for MW below RegMin* is the area above the DA LMP and below the Mitigated Energy Offer Curve between the greater of the MW at which the DA LMP crosses the Mitigated Energy Offer Curve and the Minimum Regulation Capacity Operating Limit divided by the capacity range between the two MW points.

### 2.10.12.10.2 Cost Increase due to Heat Rate increase during non-steady state:

The cost (in $/MW of Regulation Mileage) increase due to the heat rate increase resulting from operating the resource at a non-steady-state condition. This heat rate loss factor rate shall not exceed 0.35% of the top Regulation load MW heat rate value.

### 2.10.23 Cost increase in Variable Operations and Maintenance:

The cost increase (in $/MWh of Regulation Mileage) of variable operations and maintenance (VOM) cost resulting from operating the resource at lower MW output incurred from the provision of Regulation. Increased VOM costs shall be calculated by the following methods and shall not exceed those levels below:

The variable operation and maintenance (VOM) costs can be applied by resource type up to the following:

**Exhibit 1: VOM for all Hydro Resources or Non-Hydro Resources providing service**

- Super-critical Steam: $10.00 per MWh of Regulation
- Sub-critical Steam: $3.50 per MWh of Regulation
- Combined Cycle: $2.50 per MWh of Regulation
- Combustion Turbine: $2.00 per MWh of Regulation
- Hydro: $1.00 per MWh of Regulation
- Reciprocating Engines: $2.00 per MWh of Regulation

For example, a 100 MW sub-critical coal fired steam resource that has been providing Regulation service for a 3 year Maintenance Period. The resource was deployed for 2,000 MWh of Regulation service over the past three years and the historical total VOM = $500,000.

**Exhibit 2: Example of VOM for Non-Hydro Resources providing Regulation**
The variable O&M (VOM) is calculated using the total VOM calculated under Section 2.4. Note that the sum of total $ used to calculate VOM included here, the total VOM $ used to calculate VOM under Sections 2.3, the total VOM $ used to calculate VOM under 2.5, the total VOM $ used to calculate VOM under 2.6 and the total VOM $ used to calculate VOM under 2.7 must not exceed the total VOM $ calculated under Section 2.4.

Actual Regulation VOM incremental costs if they exceed the levels above must be submitted and evaluated pursuant to the Mitigated Offer Methodology Approval Process.

**Exhibit 3: Regulation-Up Maximum Allowable Mitigated Offer Example**

**Example: Sub-critical Coal-Fired Steam Resource, Regulation-Up Service**

<table>
<thead>
<tr>
<th>Resource Operating Mode</th>
<th>Output</th>
<th>Heat Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Regulation Capacity Operating Limit</td>
<td>100 MW</td>
<td>9,000 Btu/kWh</td>
</tr>
<tr>
<td>Maximum Economic Capacity Operating Limit</td>
<td>110 MW</td>
<td></td>
</tr>
<tr>
<td>Steam Resource Regulation Band</td>
<td>20 MW</td>
<td></td>
</tr>
<tr>
<td>Lowest Regulating Operating Load</td>
<td>40 MW</td>
<td>12,500 Btu/kWh</td>
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**Base Prices**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Fuel Cost (TFRC):</td>
<td>$2.25/mBtu</td>
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</tbody>
</table>

**Uncompensated Cost due to lower Maximum Operating Limit**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>DA LMP</td>
<td>$30.00/MWh</td>
</tr>
<tr>
<td>DA Regulation-Up Award</td>
<td>20 MW/hour</td>
</tr>
<tr>
<td>Weighted Average Energy Cost for MW Above Reg. Max Limit</td>
<td>$15.00/MWh</td>
</tr>
<tr>
<td>Uncompensated Cost</td>
<td>=[($30/MWh - $15/MWh) * (110 MW – 100 MW)] / 20MW/hour = $7.50 $/MW</td>
</tr>
</tbody>
</table>

**Total Regulation Cost (hourly)**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
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<tbody>
<tr>
<td>(a) Heat Rate Adjustment</td>
<td>3.15 mBtu/hour * $2.25/mBtu / 20 MW</td>
</tr>
<tr>
<td>(b) Regulation VOM Adder</td>
<td>$3.50/hour/MW of Regulation (for Steam Unit)</td>
</tr>
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</table>
3.4 Mitigation Measures for Operating Reserve Offers

A mitigated offer for each Operating Reserve product shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. The mitigated Operating Reserve Offers may be updated up to 1100 hours on the day before the Operating Day for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Operating Reserve Offers may be updated until the Day-Ahead RUC begins. For Resources committed by the Day-Ahead Market, the mitigated Operating Reserve Offers submitted as of 1100 hours on the day before the Operating Day will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day; for all other Resources, the mitigated Operating Reserve Offers submitted at the time the Day-Ahead RUC begins will apply to the RTBM on the Operating Day.

A. The offer conduct thresholds for each of the Operating Reserve products are as follows:

(1) For Resources with local market power as described in Section 3.1(4), the conduct threshold is a 10% increase above the mitigated offer for the applicable Operating Reserve Offer;

(2) For all other Resources, the conduct threshold is a 25% increase above the mitigated offer for the applicable Operating Reserve Offer.

B. Any Operating Reserve Offer exceeding the applicable threshold, except offers below $10/MWh, will be deemed excessive. The Transmission Provider shall
apply mitigation measures by replacing the Operating Reserve Offer with the applicable mitigated Operating Reserve Offer if:

1. The Resource’s Operating Reserve Offer exceeds the applicable mitigated offer by the conduct threshold; and
2. The Resource has local market power as determined in Section 3.1; and
3. The Resource either:
   a. Fails the Market Impact Test as described in Section 3.7, or
   b. Has local market power as described in Section 3.1(4).

The mitigated Spinning Reserve Offer shall be equal to zero for Resources other than combustion turbines, reciprocating engines and hydro Resources operating as a synchronous condenser. No known incremental costs are incurred for providing Spinning Reserve from other resource types.

Total mitigated Spinning Reserve Offer for combustion turbines, reciprocating engines and hydro Resources operating as a synchronous condenser shall not exceed any additional fuel related costs, maintenance costs and power consumption costs necessary for the Resource to be prepared for deployment of Spinning Reserve:

Mitigated Spinning Reserve Offer ($/MW) ≤

\[(\text{Additional Fuel Cost}($/Hr) + \text{Additional Maintenance Cost} ($/Hr) + \text{Condensing Power Cost} ($/Hr)) / \text{Spinning Reserve MW}\]

The mitigated Spinning Reserve Offer shall not exceed the sum of any increased fuel related costs necessary for the Resource to be prepared for deployment of Spinning Reserve and any cost increase from heat rate degradation due to operating at a lower output level:

Mitigated Spinning Reserve Offer ($/MW) ≤

\[\text{Marginal Increase in Total Fuel Related Cost} + \text{Unit Specific Heat Rate Degradation due to Operating at a Lower Output Level}\]

For Demand Response Resources utilizing load reduction, the mitigated Spinning Reserve Offer shall not exceed the quantifiable costs necessary to be prepared to shut down or curtail load. For Demand Response Resources utilizing Behind The-Meter Generation the mitigated Spinning Reserve Offer shall adhere to the same definition above for generating Resources. C. The mitigated Supplemental Reserve Offer shall not exceed any fuel related costs and
labor costs necessary for the Resource to be prepared for deployment of Supplemental Reserve, and any cost increase from heat rate degradation due to operating at a lower output level:

Mitigated Supplemental Reserve Offer ($/MW) ≤

Marginal Increase in Total Fuel Related Cost + Unit Specific Heat Rate Degradation due to Operating at a Lower Output Level + Additional Labor Cost($) / Average Supplemental Reserve MW

D. The mitigated Regulation-Up Service Offer shall not exceed the sum of the cost increase due to:

1. unit specific heat rate degradation due to operating at a lower output level,

2. the heat rate increase during non-steady state operation,

3. uncompensated increase in costs attributable to moving between a lower economic and a higher regulating minimum operating limit and operating at the higher regulating minimum operating limit,

4. increase in VOM due to non-steady state operation,

5. uncompensated costs, as described in the Market Protocols attributable to moving from a higher economic to a lower regulating maximum operating limit and operating at the lower regulating maximum operating limit:

Mitigated Regulation-Up Service Offer ($/MW) ≤

Unit Specific Heat Rate Degradation due to Operating at a Lower Output Level + Cost Increase due to Heat Rate Increase during non-steady state operation + Uncompensated Minimum Operating Limit + Cost Increase in VOM + Uncompensated Cost ($/MW) ≤ Uncompensated Cost ($/MW),


Mitigated Regulation-Up Offer ($/MW) ≤ Uncompensated Cost ($/MW),

Mitigated Regulation-Up Mileage Offer ($/MW) ≤
E. The mitigated Regulation-Down Service Offer shall not exceed the sum of the cost increase due to:

1. unit specific heat rate degradation due to operating at a lower output level,

2. the heat rate increase during non-steady state operation,

3. uncompensated increase in costs attributable to moving between a lower economic and a higher regulating minimum operating limit and operating at the higher regulating minimum operating limit,

4. increase in VOM due to non-steady state operation,

5. uncompensated costs as described in the Market Protocols attributable to moving from a higher economic to a lower regulating maximum operating limit and operating at the lower regulating maximum operating limit.

Mitigated Regulation-Down Offer ($/MW) ≤

< Unit Specific Heat Rate Degradation due to Operating at a Lower Output Level + Cost Increase due to Heat Rate Increase during non-steady state operation + Uncompensated Minimum Operating Limit + Cost Increase in VOM + Uncompensated Cost ($/MW) Maximum Operating Limit

Where:


Mitigated Regulation-Down Offer ($/MW) ≤ Uncompensated Cost ($/MW), and

Mitigated Regulation-Down Mileage Offer ($/MW) ≤

(Cost Increase due to Heat Rate Increase during non-steady state operation + Cost Increase in VOM) * Regulation-Down Mileage Factor

Further details associated with the development of the exact costs in the formulas above are included in the Market Protocols.
Proposed Criteria Language Revision

N/A
**PRR Recommendation Report**

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<thead>
<tr>
<th>PRR No.</th>
<th>Marketplace-PRR149</th>
<th>PRR Title</th>
<th>Resources Not Qualified For Energy Correction</th>
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<td>Provide explanation if Expedited and/or Urgent Action is selected: This MPRR is Expedited so it can be reviewed at the October MOPC.</td>
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<td>☐ Require additional information</td>
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<td>SPP Staff will complete this section.</td>
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<tr>
<td><strong>Protocol Section(s) Requiring Revision</strong></td>
<td></td>
<td>Section No.: 4.2.2.2.2</td>
<td>Title: Dispatch Status</td>
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<td>☒ Correction/Clean-Up</td>
<td>☐ Clarification</td>
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<td>☐ Post Go-Live</td>
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<td><strong>Revision Description</strong></td>
<td></td>
<td>Resources not qualified to provide Energy (i.e. Resources such as EDRs and DDRs that are only providing Operating Reserve products) should not be subjected to the Regulation Deployment Adjustment since there is no Energy Opportunity Cost associated with provision of Operating Reserve products from these types of Resources. In Addition, because there is no submitted Energy Offer Curve, special processing is required to set the Resources Desired Dispatch MW equal to Resource actual output for proper calculated of RUC MWP Distribution Amount under Section 4.5.9.10.</td>
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<td>☒ Yes – Section No: <em>(Include a summary of impact and/or specific changes)</em></td>
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<td>Date of Vote: 9/10/2013</td>
<td>Vote: Unanimously Approved</td>
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<td>Vote: Approved with modifications</td>
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<td>Vote: Approved with no Reliability Impact</td>
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<td><strong>MOPC Recommendation</strong></td>
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<td>Vote:</td>
</tr>
<tr>
<td><strong>Board Review</strong></td>
<td></td>
<td>Date of Vote:</td>
<td>Vote:</td>
</tr>
</tbody>
</table>
4.2.2.2 Dispatch Status

There is a Dispatch Status for each product (Energy, Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve as follows:

1. Energy
   - (a) Market – The Resource is available for SPP economic dispatch if committed;
   - (b) Not Qualified – The Resource is not qualified to be dispatched to provide Energy. This status is only valid for a Demand Response Resource or External Dynamic Resource that is not available for Energy dispatch but is available to be deployed for Regulation-Up, Regulation-Down and/or Contingency Reserve. Use of the Not Qualified Status is required for an External Dynamic Resource in the Eastern Interconnection. Resources with this submitted Energy Dispatch Status are not subject to the charges and credits calculated under Section 4.5.9.19 or the deviation calculations under Sections 4.5.9.10(1)(a.5) and 4.5.9.10(1)(a.7).

2. Operating Reserve (separate status for each product)
   - (a) Market – The Resource is available to clear the Operating Reserve product based on submitted Operating Reserve Offers;
   - (b) Fixed - Market Participant is fixing the Operating Reserve product clearing at the specified MW level. The minimum level is 100 KW (0.1 MW);
     - (i) SPP may clear the Operating Reserve product above the fixed MW based on submitted Operating Reserve Offers and may only clear below the fixed MW amount during an Emergency condition.
(ii) The fixed Operating Reserve MW will be rejected if the fixed MW violates any of the Resource Offer parameters.

(c) Not Qualified – The Market Participant may specify that a Resource that was qualified in registration to provide one or more Operating Reserve products is no longer qualified to supply that product. This status must be submitted for each applicable Operating Reserve product for which a Resource was not qualified in registration to provide.

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### Proposed Tariff Language Revision

#### Attachment AE

#### 4.1 Offer Submittal

Beginning seven (7) days prior to the Operating Day, Market Participants may begin to submit Offers for use in the Day-Ahead Market and Offers for use in the RTBM. Day-Ahead Market Offers may be updated up to 1100 hours Day-Ahead and RTBM Offers may be updated thirty (30) minutes prior to each Operating Hour. Offer submittals shall conform to the following:

1. Offers submitted in the Day-Ahead Market are independent from Offers submitted in the RTBM;

2. Market Participants may specify that the Offers submitted in the Day-Ahead Market also apply in the RTBM;

   a. **Such an Offer shall be rejected in the RTBM if the Market Participant has submitted a Resource commitment status of “not participating” as described in Section 4.1(10)(e) of this Attachment AE and the Resource is not participating in the Day-Ahead Market.**

3. Submitted Resource Offers will automatically roll forward hour to hour until changed within each respective market;

4. Offers may be submitted that vary for each hour of the Operating Day, except the Offer parameters related to unit commitment as defined in the Market Protocols for which a single value is submitted. These unit commitment Offer parameters will automatically roll forward in each hour until updated;

5. Offers submitted for use in the RTBM are also used in the RUC;
(6) Resource Offers may only be submitted at Resource Settlement Locations, Import Interchange Transaction Offers may only be submitted at External Interface Settlement Locations and Virtual Energy Offers may be submitted at any Settlement Location, including a Market Hub;

(7) For Regulation Qualified Resources and Regulation-Up Qualified Resources, Market Participants may submit Resource Offers for Regulation-Up, Spinning Reserve and Supplemental Reserve. For Regulation-Down Qualified Resources and Regulation Qualified Resources, Market Participants may submit Resource Offers for Regulation-Down. For Spin Qualified Resources, Market Participants may submit Resource Offers for Spinning Reserve and Supplemental Reserve. For Supplemental Qualified Resources, Market Participants may submit Resource Offers for Supplemental Reserve. Resource qualifications are verified by the Transmission Provider as part of the registration process as follows:

(a) A Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource must pass a specific regulation test as defined in Section 2.10.3 of this Attachment AE and must be capable of deploying one hundred percent (100%) of cleared Regulation-Up and/or Regulation-Down within the Regulation Response Time for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(b) A Spin Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Spinning Reserve or cleared Supplemental Reserve within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(c) A Supplemental Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Supplemental Reserve from an off-line state within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(8) Resource Offers are limited by the Offer caps and floors specified in Section 4.1.1 of this Attachment AE;
(9) The Resource Offer parameters that constitute a valid Offer for use in either the Day-Ahead Market or RTBM are submitted using the data formats, procedures, and information defined in the Market Protocols and will include the following (as further defined in the Market Protocols):

- Resource Name
- Resource Type
- Start-up Offer
- No-Load Offer
- Energy Offer Curve
- Regulation–Up and Regulation-Down Offers
- Spinning and Supplemental Reserve Offers
- Sync-To-Min and Min-To-Off Times
- Start-Up Time
- Hot to Intermediate and Hot to Cold Times
- Maximum Daily and Weekly Starts
- Maximum Daily Energy
- Maximum and Minimum Run Times
- Minimum Down Time
- Minimum Emergency Capacity Operating Limit and Run Time
- Minimum Normal, Economic, and Regulation Capacity Operating Limits
- Maximum Normal, Economic, and Regulation Capacity Operating Limits
- Maximum Emergency Capacity Operating Limits and Run Time
- Maximum Quick-Start Response Limit
- Ramp-Rate-Up and Ramp-Rate-Down
- Turn-Around Ramp Rate Factor
- Regulation Ramp Rate
- Contingency Reserve Ramp Rate
- Resource Status
- JOU Ownership Share

(10) Market Participants must specify a Resource commitment status as part of the Resource Offer using the data formats, procedures, and information defined in the Market Protocols. Market Participants use the commitment status to indicate;
(a) Whether they are self-committing a Resource;
(b) Whether the Resource may be committed by the Transmission Provider;
(c) Whether the Resource may be committed by the Transmission Provider only to alleviate an anticipated Emergency Condition or local reliability issue;
(d) Whether the Resource is on an outage; or
(e) Whether the Resource is not participating in the Day-Ahead Market.

(11) Market Participants must specify a Resource dispatch status as part of the Resource Offer using the data formats, procedures and information defined in the Market Protocols. Market Participants use the dispatch status to notify the Transmission Provider whether the Resource is:
   (a) Eligible for Energy Dispatch;
   (b) Eligible for Operating Reserve clearing; or
   (c) Self-scheduled for Operating Reserve.

   If the dispatch status for a Resource does not indicate it is eligible for Energy Dispatch, then such Resource shall not be subject to charges and credits calculated under Section 8.6.15 of this Attachment AE and shall not be subject to the deviation calculations under Sections 8.6.7A(2)(e) and 8.6.7A(2)(g) of this Attachment AE.

(12) Resource limits submitted as part of the Resource Offer must pass the validation rules defined in the Market Protocols, otherwise, the Resource Offer will be rejected; and

(13) The Market Participant must comply with the must-offer requirements as defined in Section 2.11 of this Attachment AE.

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**Proposed Criteria Language Revision**

N/A
Southwest Power Pool, Inc.
MARKETS AND OPERATIONS POLICY COMMITTEE
Recommendation to the Board of Directors
October 29, 2013

Organizational Roster
The following members represent the System Protection Working Group:

Rick Gurley, Chairman
Lynn Schroeder
Heidt Melson
Louis Guidry
Ken Zellefrow
Matthew Thykkuttathil
Brent Carr
Bud Averill
Ron McIvor
Steve Wadas
Shawn Jacobs
Tom Miller
Doug Bowman, Secretary

American Electric Power (AEP)
Westar Energy (WR)
Xcel Energy
Cleco
City Utilities of Springfield, Missouri
Sunflower Electric
Arkansas Electric Cooperative (AECC)
Grand River Dam Authority
Omaha Public Power District
Nebraska Public Power District
Oklahoma Gas & Electric (OG&E)
ITC Great Plains
Southwest Power Pool (SPP)

Background
In 2011, the SPCWG requested SPP staff produce an Underfrequency Load Shedding Plan (UFLS Plan) that would develop, coordinate, and document the requirements for automatic underfrequency load shedding (UFLS) programs within the SPP RTO. The plan’s objective was to provide SPP and UFLS owners guidance in meeting compliance requirements in accordance with NERC PRC-006-1. The UFLS plan was completed before the October 1, 2013 deadline set by NERC.

The UFLS Plan was completed and received MOPC endorsement on July 16, 2013.

SPP criteria section 7.3 is supported by the SPCWG. It outlines, among other things, automatic underfrequency load shedding requirements. In addition, Section 7.8.4 covers automatic underfrequency load shedding requirements during generator frequency excursions. It was realized that the UFLS plan, when effective, would conflict with these sections of the criteria.

The SPCWG voted unanimously on October 1, 2013 to remove those sections of the criteria that conflicted with the new UFLS plan.

Recommendation
1. MOPC Recommends that BOD approve the removal of those criteria sections pertaining to automatic underfrequency load shedding.

Approved: MOPC October 15-16, 2013
Approved unanimously
7.0 SYSTEM PROTECTION EQUIPMENT

7.3 UNDER-FREQUENCY LOAD SHEDDING AND RESTORATION

7.3.1 Automatic Load Shedding

A major disturbance among the interconnected bulk electric system may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. The areas of separation are unpredictable. To provide load relief and minimize the probability of network collapse the following practices are established. For more details refer to SPP UFLS Plan and NERC PRC-006-1.

7.3.1.1 Operating Reserve

All SPP operating reserve shall be utilized before resorting to shedding firm load. During a period of declining frequency, there may be violent swings of both real and reactive power. For this reason, all generator governors and voltage regulators shall be kept in automatic service as much as practical.

7.3.1.2 Operating Principles

a. To realize the maximum benefit from a load shedding program the points at which the load is shed in a company area shall be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

b. The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining frequency. The only practical way to remove load from a member in an attempt to stabilize the frequency is to do so automatically by the use of under-frequency relays. Since a geographical area or the timing of a period of low frequency cannot be predicted, all of the designated under-frequency relays on a member system shall be in service at all times. Under-frequency relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

c. The accepted practice of the electric industry is to shed load in a minimum of three steps. Should the frequency continue to decline after these three steps of...
load shedding, additional action may be required to protect generating machinery from mechanical damage. The actions may include opening of tie-lines, removal of generating units from the bus, additional steps of load shedding, or "island" operation may be utilized automatically with enough load left on a machine or plant to keep it in operation. A member can elect to use any one or a combination of these actions. It is recommended that this operation be performed at 58.5 Hz. Whatever is done by any one member shall be coordinated with neighboring members. A map or chart which shows additional actions that will be taken below a frequency of 58.7 Hz shall be furnished to SPP.

7.3.1.3 Implementation

a. Should the utilization of spinning reserve fail to stop a frequency decline, load shedding shall be initiated in steps as indicated below. The goal of the program is to prevent a cascading outage due to a frequency excursion and restore the system to a stable condition. Members must be ready to shed, in three steps, an accumulated minimum of thirty (30) percent of a member's current load. Current load shall be deemed as the one-minute average of the member's load prior to the first under-frequency relay action taken at 59.3 Hz. If system frequency decay is permanently stabilized to 60 Hz after UFLS implementation of Step 1 or Step 2 of the three steps of under-frequency load shedding (UFLS), it is not required to continue with the additional UFLS step(s).

This requirement shall be achieved as follows:

a. A member may dynamically arm and disarm UFLS relays to achieve the required load shedding totals, indicated in the chart below, by utilizing a load following program. For the purposes of this section, the term ‘dynamically’ means that no operator intervention is required to arm or disarm a UFLS relay, or

b. A member that does not dynamically arm and disarm UFLS relays shall install, or have installed on its behalf, UFLS relays with a total capability of shedding an accumulated minimum of thirty (30) percent of the member’s current load up to a maximum of forty-five (45) percent. The relays shall be set to shed the accumulated minimum of thirty (30) percent total up to a maximum of forty-five (45) percent as indicated in the chart below. Ideally, members would shed load in three increments of 10% each; however, due to varying load profiles, it is
acceptable to shed increments of load as indicated in the chart below. At Step 1, the member is required to shed at least 10% of their current load but no more than 15%. At Step 2 the member is required to shed at least 20% of their current load but no more than 25%, and Step 1 load shedding may be considered an integral portion of Step 2. At Step 3 the member is required to shed at least 30% of their current load but no more than 45%, and Step 1 and Step 2 load shedding may be considered an integral portion of Step 3. For UFLS tripping of loads greater than 15% at Step 1, 25% at Step 2 and 45% at Step 3, a waiver must be acquired from SPP and any applicable SPP working group. Once installed, these UFLS relays shall remain in service to trip loads except for periods of testing and maintenance.

Regardless of the technique utilized only the non-intentional delays including operating times of relays and breakers, plus any intentional delay as allowed in Criteria 7.3, shall delay the interruption of pre-event load for all events at the time of each event.

The ideal load shedding progression for a 1000 MW load would be:

<table>
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<tr>
<th>Step</th>
<th>Frequency (Hz)</th>
<th>Accumulated Load Relief</th>
<th>Total load dropped (MW)</th>
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<tr>
<td>1</td>
<td>59.3</td>
<td>10% of 1000</td>
<td>100</td>
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<tr>
<td>2</td>
<td>59.0</td>
<td>20% of 1000</td>
<td>200</td>
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<tr>
<td>3</td>
<td>58.7</td>
<td>30% of 1000</td>
<td>300</td>
</tr>
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</table>

This should be followed as far as practical.

<table>
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<tr>
<th>Step</th>
<th>Frequency (Hz)</th>
<th>Minimum Accumulated Load Relief (%)</th>
<th>Maximum Accumulated Load Relief (%)</th>
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<tbody>
<tr>
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<td>15</td>
</tr>
<tr>
<td>2</td>
<td>59.0</td>
<td>20</td>
<td>25</td>
</tr>
<tr>
<td>3</td>
<td>58.7</td>
<td>30</td>
<td>45</td>
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</table>

The following example is an acceptable progression of load shedding and meets SPP Criteria:

One-minute average load prior to first load shedding step is 1000MW

<table>
<thead>
<tr>
<th>Step</th>
<th>Frequency (Hz)</th>
<th>Load Shed (MW)</th>
<th>Load-Shed this Step (%)</th>
<th>Total Load Shed (MW)</th>
<th>Accumulated % Total Load Shed</th>
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<td>120</td>
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The following example is not an acceptable progression of load shedding by failing to meet SPP load shedding criteria to shed a minimum accumulation of 20% of the total load at Step 2:

One minute average load prior to first load shedding step is 1000MW

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<th>Total Load Shed (MW)</th>
<th>Accumulated % Total Load Shed</th>
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<tr>
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<td>59.0</td>
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<td>190</td>
<td>19</td>
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<td>3</td>
<td>58.7</td>
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<td>300</td>
<td>30</td>
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</table>

The following example is not an acceptable progression of load shedding by failing to meet SPP load shedding criteria by exceeding the maximum accumulated load shed of 15% at Step 1:

One minute average load prior to first load shedding step is 1000MW

<table>
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<tr>
<th>Step</th>
<th>Frequency (Hz)</th>
<th>Load Shed (MW)</th>
<th>Load Shed this Step (%)</th>
<th>Total Load Shed (MW)</th>
<th>Accumulated % Total Load Shed</th>
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b. The relays used to accomplish load shedding shall be high speed with no external intentional time delay devices employed. An exception to this policy would be on circuits serving considerable motor load (such as oil field or irrigation pumping load) which would cause the under-frequency relays to incorrectly operate when the source voltage is removed momentarily due to a transmission line fault.

c. In special cases, some members may elect to shed more than the allowable maximum of the system load on any step, for example, if they have an adverse ratio of load responsibility to generating capability. This situation should not be general and shall be considered on the
merits of specific cases. As stated in requirement 2 of 7.3.1.3.a, in such cases, a waiver should be acquired from SPP and any applicable SPP working group.

d. The tripping of any generating unit by under-frequency relays or any other protective device during low frequency conditions shall be so coordinated that these units will not be tripped before the three steps of load shedding have been utilized. Should this not be practical due to the operating characteristics of certain units, then these members shall protect the interconnected systems by shedding a block of load equal to the capability of the generating unit that will be tripped and at the frequency which will remove the unit from service. If the unit is jointly owned, each of the joint owners shall shed a block of load equal to their share of the unit.

e. The coordination among members becomes critical when actions beyond Step 3 are utilized; particularly, on those members which have established extra high voltage (EHV) terminals as part of their transmission system and/or with generators connected directly to the EHV system. Careful consideration shall be given when opening only one end of an EHV line section which is energized; the open-ended voltage could rise to damaging levels and reactive flow towards the closed end could have intolerable effects. Further, if generation is connected to the affected portion of the EHV network, that generating capability would be removed from an area where it is sorely needed. Consideration shall be given to the coordination of under-frequency relaying of the EHV transmission to maintain generating units on line and if necessary, carry portions of a neighboring system load to do so. System operators shall be alert to the effects of unloading the EHV network and be prepared to remove portions of the network should the voltage rise to intolerable levels.

7.3.1.4 Required Location And Model Data Reporting For Under-frequency Load Shedding Equipment

The number, type and location of Under-frequency Load Shedding (UFLS) equipment will normally be the responsibility of the facility owners based on recommendations by the owners’ or SPP’s studies. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in databases by the SPP staff for a period of at least three (3) years. These modeling databases shall be monitored as necessary by the SPP System Protection and Control Working Group (SPCWG). The Model Development Working Group, Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities is installed at critical locations throughout the system as determined in power flow and dynamic stability studies. The specific data that is required in SPP’s circuit analysis models shall be maintained and
submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, location, breaker, trip frequencies, amount of load shed by trip frequency, relay and breaker operating times, and any intentional delay of breaker clearing. Also required will be any related generation protection, tie tripping schemes, islanding schemes, or any other schemes that are part of or impact the UFLS programs.

7.3.1.5 Requirements for Testing and Maintenance Procedures
Each facility owner shall have a documented maintenance program in place to test or the means (i.e. self-testing microprocessor relays) to periodically check the functionality and availability of the UFLS equipment in service. These tests shall be done based on the manufacturers’ recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer’s recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.3.1.6 Periodic Review of Under-frequency Load Shedding Equipment
SPP members shall maintain a list of substations where UFLS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the UFLS equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.3.1.4. The SPCWG will update, if necessary, this UFLS Criteria every three (3) years.

7.3.1.7 Requests for Under-frequency Load Shedding Data
SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners should provide the requested data within five (5) business days with a copy of the requested information forwarded to
the SPP. However, it is recognized that significant disturbances may result in a large amount of equipment operations at multiple locations and that some equipment operations must be manually retrieved from the UFLS equipment’s locations. These factors may make it impractical to retrieve and properly prepare the records and documentation within five (5) business days. In these cases, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.3.1.8 Restoration

After the frequency has stabilized the following procedure shall be followed.

a. In the event the frequency stabilized below 60 Hz, system operators shall coordinate operations to utilize all available generating capacity to the maximum extent possible in order to restore the frequency to 60 Hz. Deficient systems shall continue to shed load until the frequency can be restored to normal.

b. At 60 Hz the isolated areas shall be synchronized with the remainder of the interconnected systems. Synchronization between individual members shall be performed only upon direct orders of the system operators of both companies involved.

c. System operators shall coordinate load restoration as generating capability, voltage levels and tie-line loadings allow.

d. Any shed load shall be restored only upon direct orders of the system operator. Extreme care shall be exercised as to the rate at which load is restored to the system in order that limits of generation and transmission line loading are not exceeded. Insofar as possible, supervisory control shall be used to restore load; otherwise, manual restoration is preferable to insure positive control by the system operators.

e. It is recommended that a restoration plan be furnished by each company for use by its system operators for implementation of a coordinated and successful recovery.

7.3.2 Requirements of a Regional Under-frequency Load Shedding Program

The SPP shall develop, coordinate, and document a Regional UFLS program.
7.3.2.1 SPP’s Coordination of Under-frequency Load Shedding Program

This program shall coordinate UFLS programs within the sub-regions, Region, and where appropriate, among Regions. It shall also coordinate the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration. For an effective plan, SPP shall coordinate programs including generation protection and control, under-voltage load shedding, Regional load restoration, and transmission protection and control. Details to be included shall include those specified in 7.3.1.4. SPP shall periodically conduct and document a technical assessment of the effectiveness of the design and implementation of its UFLS program. The first technical assessment of the program shall be completed by SPP no later than June 1, 2001. These assessments shall be completed at least every five years thereafter or as required by significant changes in system conditions. The documented results of such assessments shall be provided to NERC on request.

7.3.2.2 Coordination of Under-frequency Load Shedding Programs And Analyses With SPP

The facility owners and operators of an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements including automatically shedding load in the amounts and at the locations, frequencies, rates and times consistent with those Regional requirements. When an under-frequency event occurs which is below the initializing set points of their UFLS programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.3.1.7.

7.3.3 Manual Load Shedding

A situation can arise when a control area must reduce load even though the frequency is normal. Since an automatic load shedding program will be of no avail in this case, manual load shedding procedures shall be utilized. One of the basic principles of interconnected operation is that a control area will match the area generation to area load at 60 Hz at all times. Should a generation deficiency develop for any reason, arrangements shall be made with adjacent control areas to cover the deficiency; but failing this, the affected control area shall reduce the area load until the available generation is sufficient to match it. In some cases a generation deficiency can be foreseen and will develop gradually; whereas, in other cases the deficiency will develop immediately with no
forewarning. A gradually developing deficiency can probably be offset by using conservation procedures; whereas, an immediate deficiency will probably require customer service interruption. The importance of a load reduction plan cannot be overemphasized. A plan is offered here which can be modified to fit individual cases.

7.3.3.1 Conservation

a. Interruption of service to interruptible customers. Utilize to the extent that the situation requires.

b. Reduction of load in company facilities.

c. Reduction of distribution voltage level. Utilize to the extent possible and as the situation requires.

d. Load reduction by request to company employees and general public. The company employees and the general public shall be notified through news media to curtail the use of electricity.

e. Load reduction by request to bulk power users. Concurrent with voltage reduction and asking employees and the general public to reduce load, bulk power users (municipals and cooperatives) will be asked to reduce load in their areas using the same methods.

f. Load reduction by large use customers. Large use commercial and industrial customers will be requested to curtail electric power usage where such curtailment will not seriously disrupt customers' operations.

7.3.3.2 Service Interruption

Manual load interruption shall be implemented by a pre-determined plan, an example of which follows.

a. Each company operating subdivision shall select distribution circuits in approximately 5% increments in the order of their priority that will be taken out of service. The 5% increments will be labeled "A", "B", "C", "D", "E", and "F". The interruption and the restoration of these circuits will be under the control of the system operator. When the system operator determines that load must be reduced, he shall direct the subdivision operators to open all "A" circuits. This will reduce the system load 5%. If further load reduction is necessary, the system operator shall direct all "B" circuits to be opened which will result in an additional 5% reduction. This shall continue through "C", "D", "E", and "F" until the generation deficiency is eliminated.
b. The objective of this plan is to have no circuits open more than two hours. If the duration of the system emergency exists in excess of two hours and only the "A" circuits have been opened, then at the end of two hours the "B" circuits shall be opened and the "A" circuits reclosed. If a 10% reduction is necessary, "C" and "D" circuits shall be opened and "A" and "B" reclosed, after "A" and "B" have been open for two hours. Obviously, no circuits shall be open longer than is absolutely necessary. The "E" and "F" circuits shall be opened to avoid opening "A" and "B" circuits twice in one day.

c. When a generation deficiency develops, or begins to develop, the system operator shall alert all involved operating personnel to the effect that certain circuits may have to be interrupted. This action will reduce the time required to execute circuit interruption orders of the system operator. Some control areas in SPP have extensive supervisory control systems while others have little, if any, supervisory control. Obviously, any implementation plan shall make best use of available equipment.

7.8 Generator Controls – Status and Operation

7.8.1 Generator Excitation System Control Operation

All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation systems in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved by the control area operator.

7.8.1.1 Reporting Procedures

Control Area Operators shall implement procedures that require Synchronous Generator Operator/Owners to provide information to the Control Area Operator, SPP, and NERC upon request (30 business days) concerning the generators’ automatic voltage control regulator. The procedures shall include the following.

a. Summary report showing the number of hours each synchronous generator did not operate in automatic voltage control mode during each calendar month. Information shall be provided on the “Generator Owner/Operator Excitation System Summary Report” supplied by SPP, if control area operator does not have its own form.
b. Detailed reports of the date, duration, and reason for each instance in which a synchronous generator was not operated in the automatic voltage control mode for a specific calendar month. Information shall be provided on the “Generator Unit Excitation System Status Report” supplied by SPP, if control area operator does not have its own form.

c. The Generator Owner/Operator shall retain the reports mentioned in (a.) and (b.) for a period of 12 rolling months.

7.8.1.2 Exempt Generators
Control Area operators shall have criteria stating which generators may be exempt from these procedures. Exemptions shall include the following.

a. Generator output less than 20MW
b. Other criteria as control area operator deems appropriate.

7.8.2 Generator Operation for maintaining Network Voltage
Synchronous generators shall maintain a network voltage or reactive power output as required by the control area operator within the reactive capability of the units.

7.8.2.1 Control Area Responsibilities
a. Each control area operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator at a specified bus and shall provide this information to the generator owner/operator. Documentation of the information shall be provided on the “Generator Owner/Operator Voltage Schedule Requirements” report supplied by SPP, if the control area operator does not have its own form. This information shall be made available to SPP and NERC on request (30 business days).

b. Each control area operator shall maintain a list of synchronous generators that are exempt from the requirement of maintaining a network voltage or reactive schedule. The list of exempt generators shall be made available to SPP and NERC on request (30 business days) and shall be supplied on “Control Area Operator’s List of Exempt Generators” report supplied by SPP, if control area does not have its own form.

7.8.2.2 Generator Owner/Operator Responsibility
a. Synchronous generator owner/operators shall maintain the voltage or reactive output as specified by the control area operator.

b. When requested by SPP and NERC, the synchronous generator owner/operator shall provide (30 business days) a log that specifies the date duration, and reason for not maintaining the established voltage or reactive schedule, along with approvals for such operation received from the transmission operator. This information shall be provided on the “Generator Unit Voltage Schedule Status Report” supplied by SPP, if control area operator does not have its own form.

7.8.3 Generator Step-Up and Auxiliary Transformer Tap Settings

Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

7.8.3.1 Reporting Procedures

Control Area operators shall implement procedures concerning the reporting and changing of transformer tap settings. The procedures shall at a minimum include the following.

a. Owner/Operators shall provide current tap settings, tap setting ranges, and impedance data for all Generator Step-Up (GSU) and Auxiliary Transformers to the control area operator, SPP, and NERC upon request (30 business days). This information shall be supplied on ‘Generator Unit Transformer Tap Setting Report” supplied by SPP is control area operator does not have its own form.

b. When tap setting changes are necessary, the control area operator shall notify generator owner/operator with “Generator Unit Transformer Tap Setting Change Request” supplied by SPP, if control area operator does not have its own report. In this report, tap setting changes are specified along with a technical justification for the changes.

c. Generator Owner/Operators shall have a period of nine (9) months in which tap setting changes must be made. After setting changes have been made, Generator Owner/Operator shall supply new “Generator Unit Transformer Tap Setting Report” for the affected generating station.

d. Criteria for Generating units whose GSU and AUX transformers would be exempted.

e. List of generating units that meet exemption criteria shall be documented on “Generation Units Exempt from Tap Setting Reporting Procedures” report supplied by SPP, if Control Area Operator does not have its own form.
7.8.4 Generator Performance during Temporary Excursions

7.8.4.1 Excursions in Frequency and Voltage
Generators shall be able to sustain temporary excursions in under frequency and over frequency. The protective relay systems regarding these conditions shall be coordinated with SPP system under frequency load-shedding schemes.

SPP's under frequency load-shedding plan allows for three stages of load shed at frequencies of 59.3, 59.0, and 58.7 Hz. The members shall shed 10% of their load at each stage in an effort to stop the decline in frequency. Control Areas may elect to implement a fourth stage at 58.5 Hz which can call for the opening of tie-lines, removal of generating units from buses, additional steps of load shedding, or the breakup of the transmission system into predetermined islands with balanced amounts of generation and load in each island. Due to the structure of the under frequency load-shedding plan, it is necessary that generators be able to sustain frequencies to at least 58.5 Hz so that the load-shedding plan works as designed. Any generator that must trip off line prior to system frequency declining to 58.5 Hz must have a block of load equal to the generator's output capability tripped at the same frequency as the generating unit.

During Emergency and/or transient system conditions, all reasonable measures should be taken to avoid tripping of the generator due to high or low voltage.

7.8.4.2 Excursions in Real and Reactive Power Output
Generators shall be able to sustain temporary excursions in real and reactive power output that may occur during a period of declining frequency or voltage. For this reason, all generator governors and automatic voltage regulators shall be kept in automatic mode as much as practical. A generator shall not trip during stable power swings except when that particular generator is out of step with the remainder of the system.

Generators shall be able to run at maximum rated reactive and real output according to each unit's Capability Curves during emergency conditions for as long as acceptable frequency and voltages allow the generator to continue to operate.
7.8.4.3 Exempt Generators
Generators shall be exempt from this section if they meet the following criteria:
Generator output less than 20MW

7.8.5 Generator Voltage Regulator Controls and Limit Functions
Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator’s short term duration capabilities and protective relays.

7.8.5.1 Reporting Procedures
Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with information that ensures generator controls coordinate with the generator short term duration capabilities and protective relays. The information shall be supplied on the “Voltage Regulator Control Setting Status Report” as supplied by SPP is control area operator does not have its own form.

7.8.6 Governor Control Operation
Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency. Governors’ speed regulation response shall be set such that a decrease in system frequency causes the governor to respond by increasing the generator real power output.

7.8.6.1 Reporting Procedures
a. Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with the characteristics of the generator’s speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance. Information shall be supplied on “Generator Governor Characteristic Reporting” report supplied by SPP if control area operator does not have its own form.

b. Non-functioning or blocked speed/load governor controls shall be reported to control area, SPP, and NERC on request (30 business days). Information shall be supplied on “Non-Functioning Governor Control” report supplied by SPP if control area operator does not have its own form.
Organizational Roster

The following persons are members of the Regional Tariff Working Group:

- Dennis Reed, WR (Chair)
- Charles Locke, KCPL (Vice-Chair)
- Richard Andrysik, LES
- Bill Dowling, Midwest Energy
- Luke Haner, OPPD
- Tom Hestermann, Sunflower
- Rob Janssen, Dogwood
- David Kays, OGE
- Lloyd Kolb, Golden Spread
- Tom Littleton, OMPA
- Bernie Liu, Xcel

- Paul Malone, NPPD
- Walt Cecil, MoPSC
- Robert Pennybaker, AEP
- Neil Rowland, KMEA
- Robert Shields, AECC
- Keith Tynes, ETEC
- John Varnell, Tenaska
- Bary Warren, EDE
- Mitch Williams, WFEC
- Brenda Fricano, SPP (Staff Secretary)

Background

Please see the TRR Recommendation Reports for TRRs 078, 097, 101, 105, 106IM, 107, 108 and 109M that were included in the MOPC October 15 – 16, 2013 background materials.

Analysis

Please see the TRR Recommendation Reports for TRRs 078, 097, 101, 105, 106IM, 107, 108 and 109M that were included in the MOPC October 15 – 16, 2013 background materials.

Recommendation

The RTWG recommends that the MOPC approve its request regarding Tariff Revision Requests 078, 097, 101, 105, 106IM, 107, 108 and 109M.

Action Requested: Approval of RTWG’s request on TRRs 078, 097, 101, 105, 106IM, 107, 108 and 109M.

APPROVAL: MOPC October 15-16, 2013

- Approved unanimously TRR 107 with as modified with new language
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<tr>
<td>078</td>
<td>Corrections to deviation calculations under Section 8.6.7 of Attachment AE.</td>
<td>September 26, 2013 Approved unanimously</td>
</tr>
<tr>
<td>097M</td>
<td>To add language into the Marketplace Tariff identical to that language approved for compliance with Order No. 760 in Docket No. ER12-2479 (filed on August 20, 2012 and approved on October 15, 2012).</td>
<td>August 21, 2013 Approved unanimously</td>
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<td>101</td>
<td>Incorporate NAESB standards by reference into Attachment R-1 of the Tariff. They are 1) NAESB Phase II Demand Response measurement and verification and 2) NAESB Energy Efficiency Standards.</td>
<td>September 25, 2013 Approved unanimously</td>
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<td>105</td>
<td>The offer cap calculation inputs are revised each year per ER06-451 (March 20, 2006 Order). The calculations are performed by SPP and filed with FERC for approval with an effective date of January 1 of the upcoming year for use in daily offer cap calculation.</td>
<td>September 25, 2013 Approved unanimously</td>
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<td>106IM</td>
<td>Tariff revisions in Attachment X, Section 5A.2 to change the wording describing the meaning of both a negative and positive Estimated TCR Exposure (“ETCRE”). Tariff Revisions in Attachment X, Section 5A.2.1 to change the word “plus” to the word “minus” consistent with the revisions in Section 5A.2.</td>
<td>September 11, 2013 Approved unanimously</td>
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<td>107</td>
<td>Revisions to Attachment V to implement the changes the Generator Interconnection Improvement White Paper.</td>
<td>September 25, 2013 Motion Passed with One Abstention (GSEC) and One Opposed (NPPD)</td>
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<td>108</td>
<td>Revisions to Article I, Section 13.7(c) to provide a Tariff mechanism to distribute any penalty revenues collected by SPP pursuant to Section 13.7 (Classification of Firm Transmission Service) of the Tariff.</td>
<td>September 26, 2013 Approved unanimously</td>
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<td>109M</td>
<td>Revisions to Article I, Section 13.7(c) to provide a Tariff mechanism to distribute any penalty revenues collected by SPP pursuant to Section 13.7 (Classification of Firm Transmission Service) of the Tariff in the Integrated Marketplace Tariff</td>
<td>September 26, 2013 Approved unanimously</td>
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<td>TRR Number</td>
<td>TRR Title</td>
<td>Marketplace MWP Cost Allocation Corrections</td>
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- The minimum limit deviation should be based on the difference between DA Market Cleared MWs and applicable minimum limits as defined in the Protocols, not the difference between DA Market and RTBM applicable minimum limits as currently defined in the Tariff.
- The maximum limit deviation should be based on the difference between DA Market Cleared MWs and applicable maximum limits as defined in the Protocols, not the difference between DA Market and RTBM applicable maximum limits as currently defined in the Tariff.
- The self-commit deviation does not apply to Resources that offered in the DA Market that were not cleared that Self-Committed prior to DA RUC. This exclusion was not included in the Tariff.
| Stakeholder Approval Required (specify date and record outcome of vote; n/a for those stakeholders not required) | MWG  
BPWG (n/a)  
TWG (n/a)  
ORWG (n/a)  
Other (specify) (n/a)  
RTWG - Approved – 9-26-2013  
MOPC  
Board of Directors |
|---|---|
| Legal Review Completed | Yes (Include any comments resulting from the review)  
No |
| Market Protocol Implications or Changes | Yes (Include a summary of impact and/or specific changes & PRR #)  
No |
| Business Practice Implications or Changes | Yes (Include a summary of impact and/or specific changes & BPR #)  
No |
| Criteria Implications or Changes | Yes (Include a summary of impact and/or specific changes)  
No |
| Other Corporate Documents Implications (i.e., SPP By-Laws, Membership Agreement, etc.) | Yes (Include which corporate documents)  
No |
| Credit Implications | Yes (Include a summary of impact and/or specific changes)  
No |
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Proposed Tariff Language Revisions (Redlined)

8.6.7 Reliability Unit Commitment Make Whole Payment Distribution Amount

An RTBM system-wide and local charge will be calculated at each Settlement Location for each Asset Owner for each hour in order to fund the payments made under Section 8.6.5. The system-wide amount will be determined by multiplying an Asset Owner’s system-wide distribution volume by a daily system-wide RUC make whole payment rate as described in Section 8.6.7(A) of this Attachment AE. The local amount will be determined for each Settlement Area impacted by a Local Reliability Issue will be determined by multiplying an Asset Owner’s local Settlement Area distribution volume by a daily local Settlement Area RUC make whole payment rate as described in Section 8.6.7(B) of this Attachment AE.

A. The RUC System-Wide Make Whole Payment Distribution Amount shall be calculated as follows:

\[
\text{The RUC System-Wide Make Whole Payment Distribution Amount} = \left[ \text{RUC System-Wide Make Whole Payment Distribution Rate} \times \text{RUC System-Wide Make Whole Payment Distribution Volume} \right]
\]

(1) The RUC System-Wide Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day as calculated under Section 8.6.5 excluding make whole payments made to Resources committed by the Transmission Provider at the request of a local transmission operator or committed by a local transmission operator to address a Local Reliability Issue, divided by the sum of Asset Owners’ RUC System-Wide Make Whole Payment Distribution Volumes for all Settlement Locations for the entire Operating Day.

(2) An Asset Owner’s RUC System-Wide Make Whole Payment Distribution Volume at a Settlement Location for an hour is equal to the sum of
following values that are calculated for each Dispatch Interval within the hour:

(a) The absolute value of the sum of actual Real-Time Settlement Location deviations from Day-Ahead Market cleared amounts for load, virtual transactions and interchange transactions except that, during any Dispatch Interval in which the Transmission Provider has declared an Emergency Condition due to a capacity shortage, Real-Time actual load deviations from Day-Ahead Market cleared amounts shall be limited to deviations associated with actual Real-Time load in excess of amounts cleared in the Day-Ahead Market;

(b) For Resources cleared in the Day-Ahead Market, (a) the positive difference between the RTBM Resource applicable minimum limits and Day-Ahead Market Resource cleared Energy quantity; or (b) if the Resource has cleared regulation in the RTBM and has not cleared regulation in the Day-Ahead Market, the positive difference between (1i) the RTBM Resource regulation minimum limit and (2ii) the greater of the Day-Ahead Market Resource cleared Energy quantity or the Resource’s Day-Ahead Market regulation minimum limits, if provided that:

(i) The applicable RTBM Resource minimum limit is greater than the comparable Day-Ahead Market Resource minimum limit. Such difference is greater by more than the Resource’s Operating Tolerance; and

(ii) The applicable RTBM Resource minimum limit is greater than the Day-Ahead Market cleared Energy amount; and

(iii) The Resource received a Dispatch Instruction less than or equal to the RTBM applicable minimum limit for at least one Dispatch Interval in the hour.

(c) For Resources cleared in the Day-Ahead Market, (a) the positive difference between the Resource Day-Ahead Market cleared Energy quantity Resource applicable maximum limits and the
RTBM Resource applicable maximum limits or (b) if the Resource has cleared regulation in the RTBM and has not cleared regulation in the Day-Ahead Market, the positive difference between (1i) the lesser of the Resource’s RTBM regulation maximum limit or the Resource’s Day-Ahead Market Resource cleared Energy quantity and (2ii) the Resource’s RTBM regulation maximum limit, provided that:

(i) The applicable RTBM Resource maximum limit is less than the comparable Resource maximum limit submitted for use in the Day-Ahead Market by more than Such difference is greater than the Resource’s Operating Tolerance; and

(ii) The applicable RTBM Resource maximum limit is less than the Day-Ahead Market cleared Energy amount; and

(iii) The Resource received a Dispatch Instruction greater than or equal to the RTBM applicable maximum limit for at least one Dispatch Interval in the hour.

(d) For Resources cleared in the Day-Ahead Market, the Resource’s Day-Ahead Market cleared amount if that Resource is off-line in the RTBM and if the Resource has not been de-committed by the Transmission Provider;

(e) For Resources that cleared in the Day-Ahead Market that are not able to follow Dispatch Instructions, the absolute value of the difference between a Resource’s actual output and the Resource’s economic operating point. The Resource’s economic operating point is calculated as described under Section 8.6.5(4)(d);

(f) For Resources that were not offered cleared in the Day-Ahead Market and that self-committed following the close of the Day-Ahead Market, and for Resources that were offered and not cleared in the Day-Ahead Market and that self-committed following the close of the Day-Ahead RUC, the actual Resource
output if the Resource received a Dispatch Instruction less than or equal to the RTBM applicable minimum limit for at least one Dispatch Interval in the hour;

(g) A Resource’s economic operating point, as calculated as described under Section 8.6.5(4)(d), for Resources that were committed following the close of the Day-Ahead Market if that Resource is off-line in the RTBM and that Resource was not de-committed by the Transmission Provider; and

(h) The absolute value of a Resource’s URD if that Resource operated outside of its Operating Tolerance and the Resource has not been exempted from URD as described under Section 6.4.1.1 of this Attachment AE.

B. RUC Local Settlement Area Make Whole Payment Distribution Amount shall be calculated as follows:

RUC Local Settlement Area Make Whole Payment Distribution Amount =

\[ (\text{RUC Local Settlement Area Make Whole Payment Distribution Rate}) \times (\text{RUC Local Settlement Area Make Whole Payment Distribution Volume}) \]

(1) The RUC Local Settlement Area Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day as calculated under Sections 8.6.5 and 8.6.6 of this Attachment AE for Resources committed within a Settlement Area by the Transmission Provider at the request of a local transmission operator or by a local transmission operator to address a Local Reliability Issue in the Settlement Area, divided by the sum of Asset Owners’ RUC Local Settlement Area Make Whole Payment Distribution Volumes within the impacted Settlement Area for the entire Operating Day.

(2) An Asset Owner’s RUC Local Settlement Area Make Whole Payment Distribution Volume for the impacted Settlement Area for an hour is equal to that Asset Owner’s Reported Load in that Settlement Area for that hour.
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**Sponsor**

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<th>Patti Kelly</th>
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<tr>
<td>E-mail Address</td>
<td><a href="mailto:pkelley@spp.org">pkelley@spp.org</a></td>
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**Tariff Section(s) Requiring Revision**

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<th>Attachment AE, Table of Contents and (new) Section 3.8</th>
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<td>Titles</td>
<td>Section 3.8 – Electronic Delivery of Data to the Commission</td>
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**Requested Resolution**

- Normal
- Urgent (provided justification below for urgent request)

**Revision Description**

Add language into the Marketplace Tariff identical to that language approved for compliance with Order No. 760 in Docket No. ER12-2479 (filed on 8/20/2012 and approved on 10/15/2012).

**Reason for Revision**

Order No. 760 requires that RTOs and ISOs “to electronically deliver to the Commission, on an ongoing basis, data related to the markets that is administers.” Paragraph 57 of Order No. 760 requires RTOs and ISOs to amend their Tariffs to reflect the requirement for the ongoing electronic delivery of data. The language included in this TRR is identical to that language which was approved in ER12-2479.

**Stakeholder Approval Required (specify date and record outcome of vote; n/a for those stakeholders not required)**

- MWG
- BPWG (n/a)
- TWG (n/a)
- ORWG (n/a)
- Other (specify) (n/a)
- RTWG – 8/21/2013 - Approved
- MOPC
- Board of Directors
## Tariff Revision Request (TRR)

| **Legal Review Completed** | □ Yes (Include any comments resulting from the review)  
Consistent with filing made originally in 2012 for the EIS Market.  
■ No |
|---------------------------|------------------------------------------------------|
| **Market Protocol Implications or Changes** | □ Yes (Include a summary of impact and/or specific changes &  
PRR #)  
■ No |
| **Business Practice Implications or Changes** | □ Yes (Include a summary of impact and/or specific changes &  
BPR #)  
■ No |
| **Criteria Implications or Changes** | □ Yes (Include a summary of impact and/or specific changes)  
■ No |
| **Other Corporate Documents Implications (i.e., SPP By-Laws, Membership Agreement, etc.)** | □ Yes (Include which corporate documents)  
■ No |
| **Credit Implications** | □ Yes (Include a summary of impact and/or specific changes)  
■ No |
| **Impact Analysis Required** | □ Yes  
■ No |
3.8 Electronic Delivery of Data to the Commission

The Transmission Provider will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission’s regulations.

Proposed Market Protocol Language Revision (Redlined)

n/a

Proposed Business Practices Language Revision (Redlined)

n/a
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### Sponsor

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<th>Sherry R. Hamilton</th>
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<tr>
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<td><a href="mailto:shamilton@spp.org">shamilton@spp.org</a></td>
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<tr>
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</tr>
<tr>
<td>Phone Number</td>
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### Tariff Section(s) Requiring Revision

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### Revision Description

Revision of Attachment R-1

### Reason for Revision

To incorporate NAESB standards by reference into Attachment R-1 of the Tariff. They are: 1)NAESB Phase II Demand Response measurement and verification (M&V) and 2)NAESB Energy Efficiency M&V Standards

### Stakeholder Approval Required

- **RTWG**— Approved – 9-25-2013
- MWG—
- BPWG—(N/A)
- TWG—(N/A)
- ORWG—(N/A)
- Other (specify)—(N/A)
- MOPC—
- Board of Directors—
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**ATTACHMENT R-1**

**North American Energy Standards Board Business Practices**

The following North American Energy Standards Board Business Practices are hereby incorporated into and made a part of this Tariff:
(1) Open Access Same-Time Information Systems (OASIS), Version 1.5 (WEQ-001, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009), with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-9.7, 001-14.1.3, and 001-15.1.2;

(2) Open Access Same-Time Information Systems (OASIS) Standards & Communications Protocols, Version 1.5 (WEQ-002, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

(3) Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.5 (WEQ-003, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

(4) Coordinate Interchange (WEQ-004, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

(5) Area Control Error (ACE) Equation Special Cases (WEQ-005, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009);

(6) Manual Time Error Correction (WEQ-006, Version 001, October 31, 2007, with minor corrections applied on Nov. 16, 2007);

(7) Inadvertent Interchange Payback (WEQ-007, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009);

(8) Transmission Loading Relief - Eastern Interconnection (WEQ-008, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

(9) Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

(10) Public Key Infrastructure (PKI) (WEQ-012, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);


(12) Measurement and Verification of Wholesale Electricity Demand Response (WEQ-015, 2008 Annual Plan Items 54(a), and 4(b), March 16, 2009); and

## Tariff Revision Request (TRR)

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<th>TRR Title</th>
<th>2014 Offer Cap Calculation Update</th>
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### Sponsor

<table>
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<tr>
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<th>Patti Kelly</th>
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<tbody>
<tr>
<td>E-mail Address</td>
<td><a href="mailto:pkelly@spp.org">pkelly@spp.org</a></td>
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### Tariff Section(s) Requiring Revision

- Section No. Attachment AF, Section – 3.2.4(a) and (b)
- Titles Calculation of Offer Caps
- Tariff Version (effective date)

### Requested Resolution

- Normal
- Urgent (provided justification below for urgent request)

### Revision Description

Each year, the offer cap calculation inputs are revised per ER06-451 (March 20, 2006 Order). The calculations are performed by SPP and filed with FERC for approval with an effective date of January 1 of the upcoming year for use in daily offer cap calculation. The numbers that are updates are the total annual fixed cost and the variable O&M cost.

### Reason for Revision

Required for the EIS Market by FERC.

### Stakeholder Approval Required (specify date and record outcome of vote; n/a for those stakeholders not required)

- MWG
- BPWG (n/a)
- TWG (n/a)
- ORWG (n/a)
- Other (specify) (n/a)
- RTWG
- MOPC
- Board of Directors

### Legal Review Completed

- Yes *(Include any comments resulting from the review)*
- No
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Proposed Tariff Language Revisions (Redlined)

From Attachment AF, Section 3.2.4:

(a) Annual Fixed Cost

The annual fixed cost of a new, natural gas-fired, combustion turbine peaking generation facility shall be based upon the calculated value of the annual carrying cost associated with the recovery of the total fixed costs to develop, build and finance such a facility plus the fixed operation and maintenance costs. Such costs shall be reviewed annually by the Transmission Provider with input from Market Participants. Any changes to such costs, along with justification for the changes, shall be filed with the Commission for approval after such review. Such costs, along with any studies justifying the costs, shall be posted electronically by the Transmission Provider. For calendar year 2013, the Annual Fixed Cost shall be equal to $133,800/Megawatt-year.

(b) Variable Non-Fuel O&M Adder

The adder equal to the estimated non-fuel variable operation and maintenance costs of a new, natural gas-fired, combustion turbine peaking generation facility shall be based on the non-fuel operating and maintenance costs of such a facility not included in the calculation of annual fixed costs as described above. Such cost shall be reviewed annually by the Transmission Provider with input from Market Participants. Any changes to such costs, along with justification for the changes, shall be filed with the Commission for approval after such review. Such costs, along with any studies justifying the costs, shall be posted electronically by the Transmission Provider. For calendar year 2013, the Variable Non-Fuel O&M Adder shall be equal to $16.24/Megawatt-hour.
Proposed Market Protocol Language Revision (Redlined)
n/a

Proposed Business Practices Language Revision (Redlined)
n/a
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**Name**
E-mail Address: ssmith@spp.org

**Company**
SPP

**Phone Number**
501-614-3200

**Date**
July 26, 2013

**Tariff Section(s) Requiring Revision**
Section Nos. 5.A.2 and 5.A.2.1 of Attachment X of the Integrated Marketplace Tariff
Tariff Version (effective date) March 1, 2014

**Requested Resolution**
☒ Normal  ☐ Urgent (provided justification below for urgent request)

**Revision Description**
Revise Section 5A.2 to change the wording describing the meaning of both a negative and positive Estimated TCR Exposure (“ETCRE”).

Revise Section 5A.2.1 to change the word “plus” to the word “minus” consistent with the revision to Section 5.A.2.

**Reason for Revision**
Congruency with Credit Management System Functional Design documents

**Stakeholder Approval Required (specify date and record outcome of vote; n/a for those stakeholders not required)**
MWG
BPWG (n/a)
TWG (n/a)
ORWG (n/a)
Other (specify) (n/a)
RTWG – 9-11-2013 – Approved
MOPC
Board of Directors

**Legal Review Completed**
☒ Yes (Include any comments resulting from the review)

No
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5A.2 Calculation of Estimated TCR Exposure (ETCRE) for TCRs that a Credit Customer Holds (ETCRE Hold). SPP will calculate the ETCRE Hold, which is an estimate of the potential value (positive or negative) of the TCR contract for the term of the TCR, for TCRs that a Credit Customer holds. A negative ETCRE Hold means SPP estimates that the potential value of the TCR will result in a payment by the Credit Customer. A positive ETCRE Hold means SPP estimates that the potential value of the TCR will result in a payment to the Credit Customer. The ETCRE Hold calculation is determined for each TCR on an individual basis. ETCRE Hold is the product of the TCR Final Reference Price times the TCR megawatts times the complete duration of the TCR. SPP will calculate the TCR Final Reference Price for each TCR based on the difference of historical Day-Ahead Market Marginal Congestion Cost (MCC) between the TCR source and TCR sink.

5A.2.1 TCR Final Reference Price. For a given source and sink combination and with respect to time (season or month) and class (on-peak and off-peak), the TCR Final Reference Price has two components: (i) a TCR Mean Price; and (ii) a TCR Stress Test Price. The Final Reference Price is the TCR Mean Price minus the TCR Stress Test Price.
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<tr>
<th>Name</th>
<th>Charles Hendrix</th>
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<tr>
<td>E-mail Address</td>
<td><a href="mailto:chendrix@spp.org">chendrix@spp.org</a></td>
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### Tariff Section(s) Requiring Revision

- Attachment V

### Requested Resolution

- Normal
- □ Urgent

Provide explanation if Urgent is selected:

### Revision Description

Revising Attachment V to implement the changes from the Generator Interconnection Improvement White Paper

### Reason for Revision

To implement the changes from the Generator Interconnection Improvement White Paper

### Stakeholder Approval Required

(Record date and outcome of vote; N/A for those stakeholders not required)

- RTWG — September 26, 2013 – Approved with One Abstention (GSEC) and One Opposed (NPPD)
- MWG — N/A
- BPWG — (N/A)
- TWG — (N/A)
- ORWG — (N/A)
- Other (specify) — (N/A)
- MOPC — Board of Directors —
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Proposed Tariff Language Revision (Redlined)
ATTACHMENT V
GENERATOR INTERCONNECTION PROCEDURES (GIP)
  including
  GENERATOR
  INTERCONNECTION AGREEMENT (GIA)
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Section 1. Definitions

**Adverse System Impact** shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

**Affected System** shall mean an electric system other than the Transmission System that may be affected by the proposed interconnection.

**Affected System Operator** shall mean the entity that operates an Affected System.

**Affiliate** shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

**Ancillary Services** shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

**Applicable Laws and Regulations** shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

**Applicable Reliability Council** shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

**Applicable Reliability Standards** shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

**Base Case** shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider.

**Breach** shall mean the failure of a Party to perform or observe any material term or condition of the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable.

**Breaching Party** shall mean a Party that is in Breach of the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable.

**Business Day** shall mean Monday through Friday, excluding Federal Holidays.

**Calendar Day** shall mean any day including Saturday, Sunday or a Federal Holiday.

**Clustering** shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection Studies.
Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by an Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable.

Definitive Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in a Preliminary Interconnection System Impact Study or that may be caused by the withdrawal or addition of an Interconnection Request, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Generator Interconnection Procedures.

Definitive Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3A of the Generator Interconnection Procedures for conducting the Definitive Interconnection System Impact Study.

Definitive Interconnection System Impact Study Queue shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for a Definitive Interconnection System Impact Study.

Dispute Resolution shall mean the procedure in Section 12 of the Tariff for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Owner’s facilities and equipment that are not included in the Transmission System. The voltage levels at which Distribution Systems operate differ among areas.
**Distribution Upgrades** shall mean the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

**Effective Date** shall mean the date on which the Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

**Emergency Condition** shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Owner’s Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Generator Interconnection Agreement to possess black start capability.

**Energy Resource Interconnection Service** shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

**Engineering & Procurement (E&P) Agreement** shall mean an agreement that authorizes the Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

**Environmental Law** shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.


**FERC** shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

**Force Majeure** shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure
event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

**Generating Facility** shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

**Generating Facility Capacity** shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

**Generator Interconnection Agreement (GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility that is included in Appendix 6 to these Generator Interconnection Procedures.

**Generator Interconnection Procedures (GIP)** shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility that are included in the Transmission Provider's Tariff.

**Good Utility Practice** shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, rather to be acceptable practices, methods, or acts generally accepted in the region.

**Governmental Authority** shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, Transmission Owner or any Affiliate thereof.

**Hazardous Substances** shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

**Initial Queue Position** shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests. The Initial Queue Position is established based upon the date and time of receipt of the valid Interconnection Requests by Transmission Provider.
**Initial Synchronization Date** shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

**In-Service Date** shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Owner’s Interconnection Facilities to obtain back feed power.

**Interconnection Customer** shall mean any entity, including the Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission System.

**Interconnection Customer's Interconnection Facilities** shall mean all facilities and equipment, as identified in Appendix A of the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

**Interconnection Facilities** shall mean the Transmission Owner’s Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

**Interconnection Facilities Study** shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Definitive Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission System. The scope of the study is defined in Section 8 of the Generator Interconnection Procedures.

**Interconnection Facilities Study Agreement** shall mean the form of agreement contained in Appendix 4 of the Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

**Interconnection Facilities Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for an Interconnection Facilities Study.

**Interconnection Feasibility Study** shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission System, the scope of which is described in Section 6 of the Generator Interconnection Procedures.

**Interconnection Feasibility Study Agreement** shall mean the form of agreement contained in Appendix 2 of the Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.
**Interconnection Feasibility Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for an Interconnection Feasibility Study.

**Interconnection Queue Position** shall mean the order of a valid Interconnection Request within the Interconnection Facilities Study Queue, relative to all other pending valid Interconnection Requests within the Interconnection Facilities Study Queue, which is established based upon the requirements in Section 4.1.3.

**Interconnection Request** shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission System.

**Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Generator Interconnection Agreement and, if applicable, the Tariff.

**Interconnection Study** shall mean any of the following studies: the Interconnection Feasibility Study, the Preliminary Interconnection System Impact Study, the Definitive Interconnection System Impact Study, the Interim Availability Interconnection System Impact Study, and the Interconnection Facilities Study described in the Generator Interconnection Procedures.

**Interconnection Study Agreement** shall mean any of the following agreements: the Interconnection Feasibility Study Agreement, the Preliminary Interconnection System Impact Study Agreement, the Definitive Interconnection System Impact Study Agreement, the Interim Availability Interconnection System Impact Study Agreement, and the Interconnection Facilities Study Agreement described in the Generator Interconnection Procedures.

**Interim Availability Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Transmission System and, if applicable, an Affected System for the purpose of providing Interim Interconnection Service. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications on an interim basis.

**Interim Availability Interconnection System Impact Study Agreement** shall mean the form of agreement contained in Appendix 5 of the Generator Interconnection Procedures for conducting the Interim Availability Interconnection System Impact Study.

**Interim Generator Interconnection Agreement (Interim GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility to allow interconnection to the Transmission System prior to the completion of the Interconnection Study process.
**Interim Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interim Generator Interconnection Agreement and, if applicable, the Tariff.

**IRS** shall mean the Internal Revenue Service.

**Joint Operating Committee** shall be a group made up of representatives from Interconnection Customer, Transmission Owner and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

**Limited Operation Interconnection Facilities Study Agreement** shall mean the form of agreement contained in Appendix 4A of the Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

**Loss** shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

**Material Modification** shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

**Metering Equipment** shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

**NERC** shall mean the North American Electric Reliability Corporation or its successor organization.

**Network Resource** shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

**Network Resource Interconnection Service** shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission System in a manner comparable to that in which the Transmission Owner integrates its generating facilities to serve Native Load Customers as a Network Resource. Network Resource Interconnection Service in and of itself does not convey transmission service.

**Network Upgrades** shall mean the additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the Interconnection Facilities
connect to the Transmission System to accommodate the interconnection of the Generating Facility to the Transmission System.

**Notice of Dispute** shall mean a written notice of a dispute or claim that arises out of or in connection with the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, or its performance.

**Party or Parties** shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

**Point of Change of Ownership** shall mean the point, as set forth in Appendix A to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Owner's Interconnection Facilities.

**Point of Interconnection** shall mean the point, as set forth in Appendix A to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, where the Interconnection Facilities connect to the Transmission System.

**Preliminary Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in an Interconnection Feasibility Study or that may be caused by an Interconnection Request, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Generator Interconnection Procedures.

**Preliminary Interconnection System Impact Study Agreement** shall mean the form of agreement contained in Appendix 3 of the Generator Interconnection Procedures for conducting the Preliminary Interconnection System Impact Study.

**Preliminary Interconnection System Impact Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for a Preliminary Interconnection System Impact Study.

**Previous Network Upgrade** shall mean a Network Upgrade that is needed for the interconnection of one or more Interconnection Customers' Generating Facilities, where the Interconnection Customer is not responsible for the cost and which is identified in Appendix A of the Generator Interconnection Agreement.

**Queue** shall mean the Interconnection Feasibility Study Queue, the Preliminary Interconnection System Impact Study Queue, or the Definitive Interconnection System Impact Study Queue, or the Interconnection Facilities Study Queue, as applicable.

**Queue Position** shall mean the order of a valid Interconnection Request within the Interconnection Feasibility Study Queue, relative to all other pending valid Interconnection Requests within the Interconnection Feasibility Study Queue, the order of a valid Interconnection Request within the Preliminary Interconnection System Impact Study Queue, relative to all other pending valid Interconnection Requests within the Preliminary Interconnection System Impact
Study Queue, or the order of a valid Interconnection Request within the Definitive Interconnection System Impact Study Queue, relative to all other pending valid Interconnection Requests within the Definitive Interconnection System Impact Study Queue, as applicable, that is established based upon the date and time of receipt of the valid Interconnection Request and the date and time of receipt of other information specified under Section 4.1 of this GIP, as applicable, by the Transmission Provider.

**Reasonable Efforts** shall mean, with respect to an action required to be attempted or taken by a Party under the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

**Scoping Meeting** shall mean the meeting between representatives of the Interconnection Customer, Transmission Owner and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

**Shared Network Upgrade** shall mean a Network Upgrade listed in Appendix A of the Generator Interconnection Agreement that is needed for the interconnection of multiple Interconnection Customers’ Generating Facilities where such Interconnection Customers share the cost.

**Site Control** shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site of sufficient size for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site of sufficient size for such purpose.

**Small Generating Facility** shall mean a Generating Facility that has an aggregate net Generating Facility Capacity of no more than 2 MW.

**Stand Alone Network Upgrades** shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. The Transmission Provider, Transmission Owner and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable.

**System Protection Facilities** shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission System or on other delivery systems or other generating systems to which the Transmission System is directly connected.
**Tariff** shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

**Transmission Owner** shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Generator Interconnection Agreement to the extent necessary.

**Transmission Provider** shall mean the public utility (or its Designated Agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

**Transmission Owner's Interconnection Facilities** shall mean all facilities and equipment owned, controlled, or operated by the Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, including any modifications, additions or upgrades to such facilities and equipment. Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

**Transmission System** shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

**Trial Operation** shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.
Section 2.  Scope and Application

2.1 Application of Generator Interconnection Procedures.

These Generator Interconnection Procedures apply, as specified in this Section 2, to the processing of Interconnection Requests for interconnections to the Transmission System that are subject to FERC jurisdiction.

2.1.1 Sections 2 through 13 apply to processing an Interconnection Request pertaining to a Generating Facility except for Small Generating Facilities that meet the requirements of Section 14 of the GIP or Appendix 11.

2.1.2 Section 14 of the GIP applies to a request to interconnect a certified Small Generating Facility meeting the certification criteria in Appendix 9 and Appendix 10.

2.1.3 A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kW shall be evaluated under Appendix 11.

2.2 Comparability.

Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this GIP. Transmission Provider will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by Transmission Provider, its subsidiaries or Affiliates or others.

2.3 Base Case Data.

Transmission Provider shall provide current base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list upon request subject to confidentiality provisions in GIP Section 13.1, that the Transmission Provider is using to perform Definitive Interconnection System Impact Studies. Transmission Provider is permitted to require that Interconnection Customer sign a confidentiality agreement before the release of commercially sensitive information or Critical Energy Infrastructure Information in the Base Case data. Such databases and lists, hereinafter referred to as Base Cases, shall include all (1) generation projects and (ii) transmission projects, including merchant transmission projects that are proposed for the Transmission System for which a transmission expansion plan has been submitted and approved by the applicable authority.

2.4 No Applicability to Transmission Service.

Nothing in this GIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.
Section 3. Interconnection Requests

3.1 General.

An Interconnection Customer shall submit to Transmission Provider an Interconnection Request in the form of Appendix 1 to this GIP and the deposit along with the other items in Section 3.3.1 of these Generator Interconnection Procedures. Transmission Provider shall apply the deposit toward the cost of the applicable Interconnection Study. Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests.

At Interconnection Customer's option, Transmission Provider and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the Interconnection Feasibility Study Agreement.

3.2 Identification of Types of Interconnection Services.

At the time the Interconnection Request is submitted, Interconnection Customer must request either Energy Resource Interconnection Service or Network Resource Interconnection Service, as described; provided, however, any Interconnection Customer requesting Network Resource Interconnection Service may also request that it be concurrently studied for Energy Resource Interconnection Service, up to the point when an Interconnection Facility Study Agreement is executed. Interconnection Customer may then elect to proceed with Network Resource Interconnection Service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed.

3.2.1 Energy Resource Interconnection Service.

3.2.1.1 The Product. Energy Resource Interconnection Service allows Interconnection Customer to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. Energy Resource Interconnection Service does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery.

3.2.1.2 The Study. The study consists of short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address
short circuit issues associated with the Interconnection Facilities. The stability and steady state studies would identify necessary upgrades to allow full output of the proposed Generating Facility and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Generating Facility without requiring additional Network Upgrades.

3.2.2 Network Resource Interconnection Service.

3.2.2.1 The Product. Transmission Provider must conduct the necessary studies and the Transmission Owner construct the Network Upgrades needed to integrate the Generating Facility in a manner comparable to that in which Transmission Owner integrates its generating facilities to serve Native Load Customers as Network Resources. Network Resource Interconnection Service allows Interconnection Customer's Generating Facility to be designated as a Network Resource, up to the Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur.

3.2.2.2 The Study. The Interconnection Study for Network Resource Interconnection Service shall assure that Interconnection Customer's Generating Facility meets the requirements for Network Resource Interconnection Service and as a general matter, that such Generating Facility's interconnection is also studied with Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on Transmission System, consistent with Applicable Reliability Standards. This approach assumes that some portion of existing Network Resources are displaced by the output of Interconnection Customer's Generating Facility. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery. The Transmission Provider may also study the Transmission System under non-peak load conditions. However, upon request by the Interconnection Customer, the Transmission Provider must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

3.3 Valid Interconnection Request.

3.3.1 Initiating an Interconnection Request.
To initiate an Interconnection Request, Interconnection Customer must submit all of the following: (i) a $10,000 deposit, (ii) a completed application in the form of Appendix 1, and (iii) demonstration of Site Control; provided, however, demonstration of Site Control is not required for inclusion of an Interconnection Request in the Interconnection Feasibility Study Queue. Specifications for acceptable site size for the purpose of demonstrating Site Control are posted on the Transmission Provider’s website, available at: http://sppoasis.spp.org/documents/swpp/transmission/studies/Interconnection%20Request%20Guidelines%20for%20Posting.pdf.; Interconnection Customer may propose an alternative site size for Transmission Provider approval. Transmission Provider shall approve a demonstration of Site Control with an alternative site size when the Interconnection Customer submits to Transmission Provider a final layout drawing of the Generating Facility that includes at a minimum: (i) the spacing and number of turbines; (ii) the cable requirements to interconnect the individual turbines to the collector substation and the cable requirements from the collector substation to the interconnection substation; (iii) the resistance and impedance measurements of the interconnecting cable and (iv) acknowledgment by Interconnection Customer that the layout drawing is intended to be final and not subsequently substantially changed. Interconnection Customer may modify the layout drawing of a project until it submits an Interconnection Request into the Definitive Interconnection System Impact Study Queue ("DISIS Queue"). Once an Interconnection Request has been submitted in the DISIS Queue, and Transmission Provider has approved the final layout drawing and demonstration of Site Control, any subsequent change to the design of the Generating Facility as depicted in the layout drawing will be subject to Section 4.4 and will be evaluated to determine whether the change constitutes a Material Modification under Section 4.4. Deposits provided pursuant to this section shall be applied toward any Interconnection Studies pursuant to the Interconnection Request.

The expected In-Service Date of the new Generating Facility or increase in capacity of the existing Generating Facility shall be no more than the process window for the regional expansion planning period not to exceed seven years from the date the Interconnection Request is received by Transmission Provider, unless Interconnection Customer demonstrates that engineering, permitting and construction of the new Generating Facility or increase in capacity of the existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by Transmission Provider by a period up to ten years, or longer where Interconnection Customer and Transmission Provider agree, such agreement not to be unreasonably withheld.

3.3.2 Acknowledgment of Interconnection Request.
Transmission Provider shall acknowledge receipt of the Interconnection Request within five (5) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement.

3.3.3 Deficiencies in Interconnection Request.

An Interconnection Request will not be considered to be a valid request until all items in Section 3.3.1 have been received by Transmission Provider; provided however, that demonstration of Site Control is not required for inclusion of an Interconnection Request in the Interconnection Feasibility Study Queue. If an Interconnection Request fails to meet the requirements set forth in Section 3.3.1, Transmission Provider shall notify Interconnection Customer within five (5) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. In the event that Transmission Provider discovers or verifies a deficiency later in the GIP process, Transmission Provider will notify Interconnection Customer as soon as practicable. Interconnection Customer shall provide Transmission Provider the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by Interconnection Customer to comply with this Section 3.3.3 shall be treated in accordance with Section 3.6.

3.3.4 Scoping Meeting.

Within ten (10) Business Days after receipt of a valid Interconnection Request, Transmission Provider shall establish a date agreeable to the Transmission Owner and the Interconnection Customer for the Scoping Meeting, and such date shall be no later than thirty (30) Calendar Days from receipt of the valid Interconnection Request, unless otherwise mutually agreed upon by the Parties.

The purpose of the Scoping Meeting shall be to discuss alternative interconnection options, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection. Transmission Provider, Transmission Owner and Interconnection Customer shall provide such technical data, including, but not limited to: (i) general facility loadings, (ii) general instability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting. Transmission Provider, Transmission Owner and Interconnection Customer will also make available personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer shall designate its Point of Interconnection, pursuant to Section 6.1, and one or
more available alternative Point(s) of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose.

3.4 OASIS Posting.

Transmission Provider will maintain on its OASIS a list of all Interconnection Requests. The list will identify, for each Interconnection Request: (i) the maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected In-Service Date; (v) the status of the Interconnection Request, including Initial Queue Position, and Interconnection Queue Position, as applicable; (vi) the type of Interconnection Service being requested; and (vii) the availability of any studies related to the Interconnection Request; (viii) the date of the Interconnection Request; (ix) the type of Generating Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); and (x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed. The list will not disclose the identity of Interconnection Customer until Interconnection Customer executes a GIA or requests that Transmission Provider file an unexecuted GIA with FERC. Transmission Provider shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Re-Study reports shall be posted to Transmission Provider's OASIS site subsequent to the meeting between Interconnection Customer and Transmission Provider to discuss the applicable study results. Transmission Provider shall also post any known deviations in the Generating Facility's In-Service Date.

3.5 Coordination with Affected Systems.

Transmission Provider will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators and, if possible, include those results (if available) in its applicable Interconnection Study within the time frame specified in this GIP. Transmission Provider will include such Affected System Operators in all meetings held with Interconnection Customer as required by this GIP. Interconnection Customer will cooperate with Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an Affected System shall cooperate with Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

3.6 Withdrawal.

Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to Transmission Provider. In addition, if Interconnection Customer fails to adhere to all requirements of this GIP, except as
provided in Section 13.5 (Disputes), Transmission Provider shall deem the Interconnection Request to be withdrawn and shall provide written notice to Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify Transmission Provider of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of Interconnection Customer's Initial Queue Position or Interconnection Queue Position, as applicable, and the forfeiture of milestone deposits provided in Sections 8.2 and 8.9, as applicable. If an Interconnection Customer disputes the withdrawal and loss of its Initial Queue Position or Interconnection Queue Position, then during Dispute Resolution, Interconnection Customer's Interconnection Request is eliminated from the applicable Queue until such time that the outcome of Dispute Resolution would restore its Initial Queue Position or Interconnection Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to Transmission Provider all costs that Transmission Provider prudently incurs with respect to that Interconnection Request prior to Transmission Provider's receipt of notice described above. Interconnection Customer must pay all monies due to Transmission Provider before it is allowed to obtain any Interconnection Study data or results.

Transmission Provider shall (i) update the OASIS list of Interconnection Requests Queue Position posting and (ii) refund to Interconnection Customer any portion of Interconnection Customer's deposit or study payments that exceeds the costs that Transmission Provider has incurred, including interest calculated in accordance with Section 35.19a(a)(2) of FERC's regulations. In the event of such withdrawal, Transmission Provider, subject to the confidentiality provisions of Section 13.1, shall provide, at Interconnection Customer's request, all information that Transmission Provider developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.
Section 4. Interconnection Request Evaluation Process

4.1 Queue Position.

4.1.1 The Transmission Provider shall assign an Initial Queue Position to each Interconnection Request based on the date and time of receipt of the valid Interconnection Requests; provided that if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and Interconnection Customer provides such information in accordance with Section 3.3.3, then Transmission Provider shall assign Interconnection Customer an Initial Queue Position based on the date the application form was originally submitted to the Transmission Provider. The Initial Queue Position of each Interconnection Request will be used solely as an identifier for the Interconnection Request.

within each study Queue as follows.

a. All Interconnection Requests The Queue Position within the Interconnection Feasibility Study Queue (“FeasibilityIFS Queue”) shall have equal priority be assigned based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and Interconnection Customer provides such information in accordance with Section 3.3.3, then Transmission Provider shall assign Interconnection Customer a Queue Position within the IFS Queue based on the date the application form was originally filed.

b. All Interconnection Requests The Queue Position within the Preliminary Interconnection System Impact Study Queue (“PISIS Queue”) shall have equal priority be assigned based upon the date and time of receipt of all items required under Section 7.2.

c. All Interconnection Requests The Queue Position within the Definitive Interconnection System Impact Study Queue (“DISIS Queue”) shall be based assigned upon the date and time of receipt of all items required under Section 8.2—have equal priority.

4.1.2 The Transmission Provider shall assign an Interconnection Queue Position for Interconnection Requests within the Interconnection Facilities Study Queue based upon the date and time the Interconnection Customer satisfies all of the requirements of Section 8.9 to enter an Interconnection Facilities Study. The priority of the Interconnection Queue Position of each Interconnection Request as determined in Section 4.1.3 will be used to determine the order of performing the Interconnection Facilities Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request.
4.1.32 A higher Queued Interconnection Request is one that has been placed "earlier" in the Queue in relation to another Interconnection Request that is lower Queued. An Initial Queue Position in the PISIS Queue shall be deemed higher than all Initial Queue Positions in the Feasibility FES Queue. An Initial Queue Position in the DISIS Queue shall be deemed higher than all Initial Queue Positions in the PISIS Queue. Once an Interconnection Customer has met all requirements for an Interconnection Facilities Study, including the execution of a Interconnection Facilities Study Agreement or a Limited Operation Interconnection Facilities Study Agreement, its Interconnection Queue Position shall be deemed higher than those in the DISIS Queue. A higher queued Interconnection Request in the Interconnection Facilities Study Queue is one that has been placed “earlier” in the Interconnection Facilities Study Queue in relation to another Interconnection Request. Interconnection Requests in the Interconnection Facilities Study Queue shall be considered to be placed in the Interconnection Facilities Study Queue at the same time if the Interconnection Requests were studied in the same Definitive Interconnection System Impact Study and each meets the requirements of Section 8.9 following the completion of that study. Moving a Point of Interconnection shall result in a lowering of Interconnection Queue Position if it is deemed a Material Modification under Section 4.4.3.

4.2 General Study Process.

The following diagram provides an overview and timeline of the Transmission Provider’s Interconnection Request submission and study process which is further described in detail in this Section 4.2 and Sections 6, 7, 8 and 9 of this GIP.
4.2.1 IFS Queue Study Procedures.

The Transmission Provider shall accept Interconnection Requests for Interconnection Feasibility Studies during a ninety (90) Calendar Day period, hereinafter referred to as the "IFSFeasibility Queue Cluster Window", every (90) Calendar Days. Following the close of the IFSFeasibility Queue Cluster Window, the Transmission Provider shall complete the study of valid Interconnection Requests within the FeasibilityIFS Queue during the (90) Calendar Day period following the close of the IFSFeasibility Queue Cluster Window as described under Section 6.3. The Transmission Provider shall, without regard to Interconnection Queue Position, simultaneously study two or
more valid Interconnection Requests within the **IFS Feasibility** Queue on the basis of geographic location and proposed electrical interconnection as specified in the Interconnection Requests in a non-discriminatory manner without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service (“Cluster Study”). The *Initial* Queue Position of an Interconnection Request shall have no bearing on the allocation of the cost of the common upgrades identified in a Cluster Study.

The Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Generating Facility. The Transmission Provider shall study individual Interconnection Requests within the **Feasibility IFS** Queue not included within a Cluster Study based upon Initial Queue Position without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service.

### 4.2.2 PISIS Queue Study Procedures.

The Transmission Provider shall accept Interconnection Requests for Preliminary Interconnection System Impact Studies during a one-hundred-eighty (180) Calendar Day period, hereinafter referred to as the "PISIS Queue Cluster Window", every one-hundred-eighty (180) days. Following the close of the PISIS Queue Cluster Window, the Transmission Provider shall complete the study of valid Interconnection Requests within the PISIS Queue in accordance with the timeline specified in Section 7.4. The Transmission Provider shall, without regard to Initial Queue Position, simultaneously study two or more valid Interconnection Requests within the PISIS Queue on the basis of geographic location and proposed electrical interconnection as specified in the Interconnection Requests in a non-discriminatory manner without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service (“Cluster Study”). The *Initial* Queue Position of an Interconnection Request shall have no bearing on the allocation of the cost of the common upgrades identified in a Cluster Study.

The Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Generating Facility.

The Transmission Provider shall study individual Interconnection Requests within the PISIS Queue not included within a Cluster Study based upon Initial Queue Position without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service.
Cluster Studies performed within the Preliminary Interconnection System Impact Study phase shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the Transmission System’s capabilities at the time of each study. In the event that an Interconnection Customer withdraws from the process at any point during the PISIS phase and that Interconnection Customer’s request was included in a Cluster Study, the Transmission Provider may substitute the next highest queued similarly situated Interconnection Request within the PISIS Queue into the current study phase, provided such substitution occurs on a non-discriminatory basis and does not have a material impact on the effort required for completion of the applicable study.

4.2.3 DISIS Queue Study Procedures.

The Transmission Provider shall accept Interconnection Requests for Definitive Interconnection System Impact Studies during a one-hundred-eighty (180) Calendar Day period, hereinafter referred to as the "DISIS Queue Cluster Window", every one-hundred-eighty (180) days. The one-hundred-eighty (180) Calendar Day period shall begin two-hundred-ten (210) days prior to the beginning of the Definitive Interconnection System Impact Study. Following the close of the DISIS Queue Cluster Window, there shall be a 30 Calendar Day review period “DISIS Review Period” to resolve any deficiencies in the Interconnection Requests received during the DISIS Queue Cluster Window. Following the DISIS Review Period, the Transmission Provider shall complete the study of valid Interconnection Requests within the DISIS Queue in accordance with the timeline specified in Section 8.54. The Transmission Provider shall, without regard to Queue Position, simultaneously study two or more valid Interconnection Requests within the DISIS Queue on the basis of geographic location and proposed electrical interconnection as specified in the Interconnection Requests in a non-discriminatory manner without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service ("Cluster Study"). The Queue Position of an Interconnection Request shall have no bearing on the allocation of the cost of the common upgrades identified in a Cluster Study.

The Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Generating Facility. The Transmission Provider shall study individual Interconnection Requests within the DISIS Queue not included within a Cluster Study based upon Initial Queue Position without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service.

Cluster Studies performed within the Definitive Interconnection System Impact Study phase shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of
the Transmission System’s capabilities at the time of each study. In the event that an Interconnection Customer withdraws from the process at any point during the Definitive Interconnection System Impact Study phase and that Interconnection Customer’s request was included in a Cluster Study, the Transmission Provider may substitute the next highest queued similarly situated Interconnection Request within the DISIS Queue into the current study phase, provided such substitution occurs on a non-discriminatory basis and does not have a material impact on the effort required for completion of the applicable study.

4.2.4 Changes to Study Procedures.

The Feasibility IFS Queue Cluster Window, the PISIS Queue Cluster Window and the DISIS Queue Cluster Window described in the following subsections have a fixed time interval based on fixed annual opening and closing dates.

Any changes to the established PISIS Queue Cluster Window or the DISIS Queue Cluster Window and opening or closing dates shall be announced with a posting on Transmission Provider’s OASIS beginning at least one hundred and eighty (180) Calendar Days in advance of changes and continuing thereafter through the end date of the first queue cluster window that is to be modified.

Any changes to the established DISIS Queue Cluster Window opening or closing dates shall be announced with a posting on Transmission Provider’s OASIS beginning at least one hundred and eighty (180) Calendar Days in advance of changes and continuing thereafter through the end date of the first queue cluster window that is to be modified.

Any changes to the established Feasibility IFS Queue Cluster Window and opening or closing dates shall be announced with a posting on Transmission Provider’s OASIS beginning at least ninety Calendar Days in advance of changes and continuing thereafter through the end date of the first queue cluster window that is to be modified.

4.2.5 Study Cost and Network Upgrade Cost Allocation.

The Transmission Provider shall determine each Interconnection Customer’s share of Interconnection Feasibility Study costs, Preliminary Interconnection System Impact Study costs and/or Definitive Interconnection System Impact Study cost by allocating 50% of the applicable study costs to Interconnection Customers pro-rata based on number of Interconnection Requests included in the applicable study and by allocating 50% of the applicable study costs to Interconnection Customers pro-rata based on requested MWs included in the applicable study.

For Network Upgrades identified in Cluster Studies, the Transmission Provider shall calculate each Interconnection Customer’s share of Network Upgrade costs in the following manner:
a. All Network Upgrades that are required to provide Interconnection Service for all Interconnection Requests included in a Cluster Study shall be included in a cluster cost allocation assessment group (“CCAAG”). The cost of each Network Upgrade component will be allocated to each Interconnection Customer in the CCAAG on a pro-rata impact basis as provided for in paragraph b below. With regard to the cost allocation, the Transmission Provider shall review all Network Upgrades and determine the earliest date that each upgrade is required to be in-service in order to provide the requested Interconnection Service (“Date Upgrade Needed”).

b. An allocation of the cost of each Network Upgrade to each Interconnection Customer shall be determined on a pro-rata basis for the positive incremental power flow impacts of the requested service on such Network Upgrade in proportion to the total of all positive incremental power flow impacts on such Network Upgrade. For each Network Upgrade identified, the average incremental power flow impact of each Interconnection Request in the Cluster Study shall be determined using each seasonal model available for the Cluster Study period during which the generating facility associated with the Interconnection Request is most likely to be generating at nameplate capacity, after the Date Upgrade Needed of such upgraded facility. Each impact amount shall be determined by first establishing a set of initial seasonal base cases that excludes flows associated with all requests included in the Cluster Study. Then each request will be added to the models and the change in flow across such Network Upgrades shall be determined for each request included in the Cluster Study. The cost of a Network Upgrade allocated to each request shall be proportional to the average positive incremental impact of each request on such Network Upgrade divided by the total average positive incremental impact of all requests included in the Cluster Study on such Network Upgrade. The cost of each Network Upgrade shall be allocated to requests independently. Incremental flows having a negative impact (counter flow) on a Network Upgrade shall be ignored.

4.3 Transferability of Queue Position.

An Interconnection Customer may transfer its Interconnection Queue Position or Initial Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change.

4.4 Modifications.
Interconnection Customer shall submit to Transmission Provider, in writing, modifications to any information provided in the Interconnection Request. Interconnection Customer shall retain its Interconnection Queue Position if the modifications are in accordance with Sections 4.4.1 or 4.4.4, or are determined not to be Material Modifications pursuant to Section 4.4.2.

Notwithstanding the above, during the course of the Interconnection Studies, either Interconnection Customer or Transmission Provider may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to Transmission Provider and Interconnection Customer, such acceptance not to be unreasonably withheld, Transmission Provider shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 8.86 and Section 8.143 as applicable and Interconnection Customer shall retain its Interconnection Queue Position or Initial Queue Position.

4.4.1 Prior to the return of the executed Definitive Interconnection Facilities System Impact Study Agreement to Transmission Provider, modifications permitted under this Section shall include specifically: (a) a decrease of electrical output (MW) of the proposed project; (b) modifying the technical parameters associated with the Generating Facility technology or the Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of cost allocation and study analysis.

4.4.2 Prior to making any modification other than those specifically permitted by Sections 4.4.1, and 4.4.4, Interconnection Customer may first request that Transmission Provider evaluate whether such modification is a Material Modification. In response to Interconnection Customer's request, Transmission Provider shall evaluate the proposed modifications prior to making them and inform Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable under Sections 4.4.1, 6.1, 8.2 or so allowed elsewhere, shall constitute a Material Modification. Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

4.4.3 Upon receipt of Interconnection Customer's request for modification permitted under this Section 4.4, Transmission Provider shall commence and perform any necessary additional studies as soon as practicable, but in no event shall Transmission Provider commence such studies later than thirty (30) Calendar Days after receiving notice of Interconnection
Customer's request. Any additional studies resulting from such modification shall be done at Interconnection Customer's cost.

4.4.4 Prior to the Effective Date of the GIA, extensions of less than three (3) cumulative years in the Commercial Operation Date of the Generating Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing. Extensions of more than three (3) cumulative years of the Commercial Operation Date of the Generating Facility are deemed to be a Material Modification. Extensions of Commercial Operation Date due to circumstances in Section 8.7 are applicable to this Section 4.4.4.
Section 5. Procedures for Interconnection Requests Submitted Prior to Effective Date of Generator Interconnection Procedures

5.1 Transition Procedures.

5.1.1 Any Interconnection Request that does not have an executed GIA or requested a GIA be filed unexecuted with FERC as of February 1, 2014 ("Revision Date") shall be subject to this GIP. Any Interconnection Customer that fails to meet these requirements shall have its Interconnection Request deemed withdrawn pursuant to Section 3.6. Any Interconnection Customer assigned a Queue Position prior to the effective date of the GIP as revised in Docket No. ER09-1254-000 and accepted by the Commission in Southwest Power Pool, Inc. v FERC ¶ 61,114 (2009) ("Revised GIP") shall retain that Queue Position subject to meeting the requirements below in Sections 5.1.1.1 and 5.1.1.2. Any Interconnection Customer that fails to meet these requirements shall have its Interconnection Request deemed withdrawn pursuant to Section 3.6.

5.1.1.1 Any Interconnection Request in the Feasibility Study Queue and the PISIS Queue will transition to the revised GIP upon the completion of the Feasibility Study or the PISIS that the Interconnection Request is being studied in at the time of the Revision Date.

All Interconnection Requests for which an Interconnection Facilities Study Agreement has been executed, including those that have a Facilities Study posted or that are in GIA negotiation process pursuant to Section 11.2 as of August 1, 2009 (or such later date resulting from the cure period pursuant to Section 3.6 of this Attachment V), shall not be required to conform to the Revised GIP with the exception of the revised requirements in Appendix 6, Section 5.1.6 of this Attachment V. Such Interconnection Requests that are included in the first transitional cluster established in Docket No. ER09-262-000 will continue to be studied in that first transitional cluster.

5.1.1.2 Any Interconnection Request in the DISIS Queue for which an Interconnection Facilities Study Agreement has not yet been executed as of the Revision Date shall be placed into the transitional DISIS Queue Cluster window that closes on the Revision Date provided it meets the requirements in Section 8.2 to be studied in the DISIS Queue by the end of the transition period. All DISIS Study Queue Interconnection Requests shall have equal priority.
5.1.1.3 **Any Interconnection Request in the DISIS Queue for which an Interconnection Facilities Study Agreement has been executed meeting all requirements in the Section 8 of the GIP, and has not executed a GIA or requested a GIA be filed unexecuted with FERC as of the Revision Date, will be assigned an Interconnection Queue Position for cost assignment purposes based upon its current DISIS Queue Cluster Window.**

All Interconnection Requests for which an Interconnection Facilities Study Agreement has not been executed as of August 1, 2009 (or such later date resulting from the cure period pursuant to Section 3.6 of this Attachment V) must conform to the Revised GIP and shall be subject to the Revised GIP. By September 30, 2009, Interconnection Customers with Interconnection Requests subject to the Revised GIP shall take all actions necessary to conform to the Revised GIP, including but not limited to revising the previously submitted Interconnection Request and providing any additional deposits required to conform to all deposit and data requirements specified under Section 3.3.1, Section 7.2 or Section 8.2 of the Revised GIP, as applicable. Interconnection Customer shall retain its priority in the applicable Queue, as determined by its deposit and data submittal, relative to the other Interconnection Customers in that respective Queue.

5.1.2 **Any Interconnection Request for which a GIA has been executed or has been filed unexecuted with FERC as of the Revision Date shall not be subject to this GIP unless the Interconnection Customer is not meeting the milestones listed in Appendix B of its GIA. An Interconnection Customer not meeting its milestones shall be required to conform to Sections 8.2 and 8.9 of this GIP. If an Interconnection Customer is not meeting the milestones in Appendix B of its GIA, the Transmission Provider shall revise the GIA to conform to this GIP and shall file such revised GIA at FERC.**

All Interconnection Requests pending in the Queue as of June 2, 2009, for which an Interconnection Facilities Study Agreement has not been executed as of August 1, 2009 (or such later date resulting from the cure period pursuant to Section 3.6 of this Attachment V.) and that satisfy the requirements of Section 5.1.1.1 above will be included in a transitional cluster window that closes on September 30, 2009. Interconnection Requests included in this transitional cluster window shall be studied in transitional clusters established for each respective IFS Queue, PISIS Queue, and DISIS Queue. If the transitional cluster window results in a transitional cluster for the IFS Queue, PISIS Queue, or DISIS Queue that includes Interconnection Requests totaling more than 15,000 MW, Transmission Provider, at its option, may divide such a transitional cluster into smaller clusters based on original Queue Position and consisting of
Interconnection Requests totaling no more than 15,000 MW. If the Transmission Provider divides the transitional cluster into smaller clusters, Transmission Provider shall base the order in which it conducts the studies of the smaller clusters on the Queue Position priority of the Interconnection Requests contained in the clusters.

5.1.3 Transition Period.

An Interconnection Customer with an Interconnection Request that has not executed a GIA as of the Revision Date shall transition to the revised GIP within sixty (60) Calendar Days of the Revision Date.

If a GIA has been submitted to FERC for approval before the effective date of the Revised GIP, then the GIA shall not be required to conform to the Revised GIP.

5.2 New Transmission Provider.

If Transmission Provider transfers control of its Transmission System to a successor Transmission Provider during the period when an Interconnection Request is pending, the original Transmission Provider shall transfer to the successor Transmission Provider any amount of the deposit or payment with interest thereon that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net amount and the deposit or payment required by this GIP shall be paid by or refunded to the Interconnection Customer, as appropriate. The original Transmission Provider shall coordinate with the successor Transmission Provider to complete any Interconnection Study, as appropriate, that the original Transmission Provider has begun but has not completed. If Transmission Provider has tendered a draft GIA to Interconnection Customer but Interconnection Customer has not either executed the GIA or requested the filing of an unexecuted GIA with FERC, unless otherwise provided, Interconnection Customer must complete negotiations with the successor Transmission Provider.
Section 6. Interconnection Feasibility Study

6.1 Interconnection Feasibility Study Agreement.

Simultaneously with the acknowledgement of a valid Interconnection Request indicating that an Interconnection Feasibility Study is to be performed, Transmission Provider shall provide to Interconnection Customer an Interconnection Feasibility Study Agreement in the form of Appendix 2. The Interconnection Feasibility Study Agreement shall specify that Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study. Within five (5) Business Days following the Scoping Meeting Interconnection Customer shall specify for inclusion in the attachment to the Interconnection Feasibility Study Agreement the Point(s) of Interconnection and up to two (2) reasonable alternative Point(s) of Interconnection. Within five (5) Business Days following Transmission Provider's receipt of such designation, Transmission Provider shall tender to Interconnection Customer the Interconnection Feasibility Study Agreement signed by Transmission Provider, which includes a good faith estimate of the cost for completing the Interconnection Feasibility Study. Interconnection Customer shall execute and deliver to Transmission Provider the Interconnection Feasibility Study Agreement along with a $10,000 deposit no later than the lesser of fifteen (15) Calendar Days after its receipt or the close of the Feasibility Queue Cluster Window. This deposit, along with the $10,000 deposit received with the Interconnection Request, will be applied towards the Interconnection Feasibility Study costs. If the Interconnection Customer’s share of the Interconnection Feasibility Study costs exceed $20,000, then Interconnection Customer will be responsible for this excess cost. If the Interconnection Customer’s share of the Interconnection Feasibility Study cost is less than $20,000, the difference shall be refunded to the Interconnection Customer, or the Interconnection Customer may elect to apply the difference as part of the deposit requirements for participation in a Preliminary Interconnection System Impact Study or Definitive Interconnection System Impact Study. On or before the return of the executed Interconnection Feasibility Study Agreement to Transmission Provider, Interconnection Customer shall provide the technical data called for in Appendix 1, Attachment A.

6.1.1 For interconnection requests not more than 2 MW the Interconnection Customer shall execute and deliver to Transmission Provider the Interconnection Feasibility Study Agreement no later than the lesser of fifteen (15) Calendar Days after its receipt or the close of the Feasibility Queue Cluster Window. The additional $10,000 deposit required in Section 6.1 does not apply. The initial $10,000 deposit received with the Interconnection request will be applied towards the Interconnection Feasibility Study cost. If the Interconnection Customer’s share of the Interconnection Feasibility Study costs exceed $10,000, then Interconnection Customer will be responsible for this excess cost. If the Interconnection Customer’s share of the Interconnection Feasibility Study cost
cost is less than $10,000, the difference shall be refunded to the Interconnection Customer, or the Interconnection Customer may elect to apply the difference as part of the deposit requirements for participation in a Preliminary Interconnection System Impact Study or Definitive Interconnection System Impact Study. On or before the return of the executed Interconnection Feasibility Study Agreement to Transmission Provider, Interconnection Customer shall provide the technical data called for in Appendix 1, Attachment A.

6.2 Scope of Interconnection Feasibility Study.

The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Transmission System. The Interconnection Feasibility Study will consider the Base Case as well as all generating facilities (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC. The Interconnection Feasibility Study will consist of a power flow and short circuit analysis. The Interconnection Feasibility Study will provide a list of facilities and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

6.3 Interconnection Feasibility Study Procedures.

Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Interconnection Requests for Interconnection Feasibility Studies may be submitted within the Interconnection Feasibility Queue Cluster Window and the Transmission Provider shall perform Interconnection Feasibility Studies every ninety (90) days. Transmission Provider shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than ninety (90) Calendar Days after the close of the Interconnection Feasibility Queue Cluster Window. At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If Transmission Provider is unable to complete the Interconnection Feasibility Study within that time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers and relevant power flow, short circuit and stability databases for the Interconnection Feasibility Study, subject to confidentiality arrangements consistent with Section 13.1.
6.3.1 **Meeting with Transmission Provider.**

Within ten (10) Business Days of providing an Interconnection Feasibility Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Feasibility Study.
Section 7. Preliminary Interconnection System Impact Study

7.1 Preliminary Interconnection System Impact Study Agreement.

Unless otherwise agreed, pursuant to the Scoping Meeting provided in Section 3.3.4, simultaneously with the delivery of the Interconnection Feasibility Study to Interconnection Customer or simultaneously with the acknowledgement of a valid Interconnection Request indicating that a Preliminary Interconnection System Impact Study is to be performed, Transmission Provider shall provide to Interconnection Customer a Preliminary Interconnection System Impact Study Agreement in the form of Appendix 3 to this GIP. The Preliminary Interconnection System Impact Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Preliminary Interconnection System Impact Study. Within three (3) Business Days following the Interconnection Feasibility Study results meeting described under Section 6.3.1, or within (3) Business Days following acknowledgement of a valid Interconnection Request indicating that a Preliminary Interconnection System Impact Study is to be performed, Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Preliminary Interconnection System Impact Study.

7.2 Execution of Preliminary Interconnection System Impact Study Agreement.

Interconnection Customer shall execute the Preliminary Interconnection System Impact Study Agreement and deliver the executed Preliminary Interconnection System Impact Study Agreement to Transmission Provider following its receipt no later than the lesser of (i) thirty (30) Calendar Days or (ii) the Calendar Days remaining prior to close of the PISIS Queue Cluster Window along with:

a. demonstration of Site Control; and

b. a $10,000 deposit for requests less than or equal to 2 MW; or

c. a $25,000 deposit for requests greater than 2 MW and less than or equal to 20 MW; or

d. a $40,000 deposit for requests greater than 20 MW and less than 100 MW; or

e. a $60,000 deposit for requests greater than or equal to 100 MW and less than 800 MW; or

f. a $90,000 deposit for requests greater than or equal to 800 MW; and

g. Technical data as denoted in Appendix 7 of this GIP, if applicable.
Failure to return the Preliminary Interconnection System Impact Study Agreement and to meet the requirements listed above will result in immediate withdrawal of the Interconnection Request.

Deposits will be applied towards the Preliminary Interconnection System Impact Study costs. If the Interconnection Customer’s share of the Preliminary Interconnection System Impact Study costs exceeds the deposited amount, then the Interconnection Customer will be responsible for this excess cost. If the Interconnection Customer’s share of the Preliminary Interconnection System Impact Study cost is less than the deposited amount, the difference shall be refunded to the Interconnection Customer, or, the Interconnection Customer may elect to apply the difference as part of the deposit requirements for participation in a Definitive Interconnection System Impact Study.

7.3 Scope of Preliminary Interconnection System Impact Study.

The Preliminary Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The Preliminary Interconnection System Impact Study will consider the Base Case as well as all generating facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

The Preliminary Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The Preliminary Interconnection System Impact Study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Preliminary Interconnection System Impact Study will provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

7.4 Preliminary Interconnection System Impact Study Procedures.

Transmission Provider shall coordinate the Preliminary Interconnection System Impact Study with any Affected System that is affected by the Interconnection Request pursuant to Section 3.5 above. Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Interconnection Requests for Preliminary Interconnection System Impact Studies
may be submitted within the PISIS Queue Cluster Window and the Transmission Provider shall perform Preliminary Interconnection System Impact Studies every one-hundred-eighty (180) days. Transmission Provider shall use Reasonable Efforts to complete the Preliminary Interconnection System Impact Study no later than one-hundred-fifty (150) Calendar Days after the close of the PISIS Queue Cluster Window.

At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Preliminary Interconnection System Impact Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Preliminary Interconnection System Impact Study. If Transmission Provider is unable to complete the Preliminary Interconnection System Impact Study within the time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer all supporting documentation, workpapers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the Preliminary Interconnection System Impact Study, subject to confidentiality arrangements consistent with Section 13.1.

7.5 **Meeting with Transmission Provider.**

Within ten (10) Business Days of providing a Preliminary Interconnection System Impact Study report to Interconnection Customer, Transmission Provider, Transmission Owner and Interconnection Customer shall meet to discuss the results of the Preliminary Interconnection System Impact Study.
Section 8. Definitive Planning Phase

8.1 Definitive Interconnection System Impact Study Agreement.

Unless otherwise agreed, pursuant to the Scoping Meeting provided in Section 3.3.4, simultaneously with the delivery of the Preliminary Interconnection System Impact Study to Interconnection Customer or simultaneously with the acknowledgement of a valid Interconnection Request indicating that a Definitive Interconnection System Impact Study is to be performed, Transmission Provider shall provide to Interconnection Customer a Definitive Interconnection System Impact Study Agreement in the form of Appendix 3A to this GIP. The Definitive Interconnection System Impact Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Definitive Interconnection System Impact Study. Within three (3) Business Days following the Preliminary Interconnection System Impact Study results meeting described under Section 7.5, or within (3) Business Days following acknowledgement of a valid Interconnection Request indicating that a Definitive Interconnection System Impact Study is to be performed, Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Definitive Interconnection System Impact Study.

8.2 Execution of Definitive Interconnection System Impact Study Agreement.

Interconnection Customer shall execute the Definitive Interconnection System Impact Study Agreement and deliver the executed Definitive Interconnection System Impact Study Agreement to Transmission Provider following its receipt no later than the lesser of (i) thirty (30) Calendar Days or (ii) the Calendar Days remaining prior to close of the DISIS Queue Cluster Window, along with each of the following:

a. Demonstration of Site Control; and

b. Study deposit, which shall be one of the following:

1. $15,000 deposit for requests less than or equal to 2 MW (See Section 13.38.4.e and 8.9.d for requirements for this deposit to be considered refundable); or

e2. $50,000 deposit for requests greater than 2 MW and less than or equal to 20 MW (See Section 13.38.4.e and 8.9.d for requirements for this deposit to be considered refundable); or

d3. $75,000 deposit for requests of greater than 20 MW and less than 75 MW (See Section 8.4.13.3e and 8.9.d for requirements for this deposit to be considered refundable); or
e4. A $150,000 deposit for requests greater than or equal to 75 MW (See Section 13.38.4.e and 8.9.d for requirements for this deposit to be considered refundable); and

fc. Definitive Point of Interconnection; and

dg. Definitive plant size (MW); and

eh. Technical information required in Appendix 7 of this GIP, if applicable; and

ig. One of the following:

i. Security deposit equal to $21,000/MW of the plant size (refundable at commercial operation or if Interconnection Request is withdrawn prior to the execution of the Interconnection Facilities Study Agreement). GIA is not executed by Interconnection Customer); or

ii. An executed contract (or comparable evidence) for the sale of electric energy or capacity from the Generating Facility; or

iii. Statement signed by an officer or authorized agent of the Interconnection Customer attesting that the Generating Facility is included in an applicable state resource plan; or

iv. Other information that the Transmission Provider deems to be reasonable evidence that the Generating Facility will qualify as a Designated Resource; or

v. Purchase Order for generating equipment specific to Queue Position or statement signed by an officer or authorized agent of the Interconnection Customer attesting that the Generating Facility is included to be supplied with turbines with a manufacturer’s blanket purchase agreement that Interconnection Customer is a party. This agreement shall be provided to Transmission Provider; or

vi. Application for an air permit (if applicable); or

vii. Filing a Notice of Proposed Construction or Alteration with the Federal Aviation Administration (if applicable).

If the Definitive Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Interconnection Feasibility Study or the Preliminary Interconnection System Impact Study, a substitute Point of Interconnection identified by Transmission Provider may be substituted for the
designated Point of Interconnection specified above without loss of Initial Queue Position, and restudies shall be completed pursuant to Section 8.8 as applicable.

8.3 DISIS Review Period

The DISIS Review Period shall be the thirty (30) Calendar Day period following the close of the DISIS Queue Cluster Window during which the Transmission Provider will validate Interconnection Requests. The Transmission Provider shall notify the Interconnection Customer of any deficiencies that would warrant removal from the DISIS Queue. Interconnection Customer shall have fifteen (15) Business Days from the date of the notice to cure any deficiencies. If the Interconnection Customer does not cure the deficiencies within such time period, the Interconnection Request shall be deemed withdrawn. Transmission Provider may conduct additional Scoping Meetings during the DISIS Review Period.

8.3.4 Scope of Definitive Interconnection System Impact Study.

The Definitive Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The Definitive Interconnection System Impact Study will consider two different scenarios as described below.

8.4.1 The “Cluster Scenario” will consider the Base Case, as well as all Interconnection Requests in the Definitive Interconnection System Impact Study Queue and all generating facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Definitive Interconnection System Impact Study is commenced:

(i) are directly interconnected to the Transmission System;

(ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request;

(iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and

(iv) have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

8.4.2 The “Stand Alone Scenario” will consider the Base Case as well as all generating facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Definitive Interconnection System Impact Study is commenced:

(i) are directly interconnected to the Transmission System;
(ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request;

(iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and

(iv) have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

The Definitive Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The Definitive Interconnection System Impact Study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Definitive Interconnection System Impact Study will provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

8.4.3 Availability of Limited Operation.

If the Definitive Interconnection System Impact Study “Stand Alone Scenario” as defined in Section 8.4.2 determines that the full amount of interconnection capacity requested by the Interconnection Customer is not available by its requested Commercial Operation Date due to transmission constraints that may be remedied by an upgrade(s) with an in-service date beyond the Commercial Operation Date proposed by the Interconnection Customer, the Transmission Provider shall quantify the amount of interconnection capacity available to the Interconnection Customer prior to the in-service date of such upgrade(s) (“Limited Operation”). The Interconnection Customer shall be notified of the amount of interconnection capacity available under the Limited Operation condition. The Interconnection Customer may choose to proceed with Limited Operation by executing the Limited Operation Interconnection Facilities Study Agreement in Appendix 4A. The Interconnection Customer may also be subject to conditions in Section 8.7 of the GIP.

8.4.4 Facilities Analysis.
During the Definitive Interconnection System Impact Study, the Transmission Provider shall specify and estimate the cost of the equipment, engineering, procurement and construction work needed for transmission facilities at the Point of Interconnection to physically and electrically connect the Generating Facility to the Transmission System (“Facilities Analysis”). The Facilities Analysis shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Transmission Owner's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities. The results of the Facility Analysis shall be utilized as part of the Interconnection Facilities Study.

The Definitive Interconnection System Impact Study scope shall the same as the Preliminary Interconnection System Impact Study scope described under Section 7.3 and shall include removal of Interconnection Requests included in the Preliminary Interconnection System Impact Study that have elected not to participate in the Definitive Interconnection System Impact Study and inclusion of any Interconnection Requests received during the DISIS Queue Cluster Window.

8.54 Definitive Interconnection System Impact Study Procedures.

a. Transmission Provider shall coordinate the Definitive Interconnection System Impact Study with any Affected System that is affected by the Interconnection Request pursuant to Section 3.5 above. Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Interconnection Requests for Definitive System Impact Studies may be submitted within the DISIS Queue Cluster Window and the Transmission Provider shall perform Definitive Interconnection System Impact Studies every one-hundred-eighty (180) days. Transmission Provider shall use Reasonable Efforts to complete the Definitive Interconnection System Impact Study no later than one-hundred-twenty (120) Calendar Days after the close of the DISIS Queue Cluster Window.

b. At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Definitive Interconnection System Impact Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Definitive Interconnection System Impact Study. If Transmission Provider is unable to complete the Definitive Interconnection System Impact Study within the time period, it shall notify Interconnection Customer and provide an estimated completion date
with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer all supporting documentation, workpapers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the Definitive Interconnection System Impact Study, subject to confidentiality arrangements consistent with Section 13.1.

e. Interconnection Customer’s study cost obligations and refunds shall be as defined in Section 13.3 with the following exception. If an Interconnection Customer withdraws from an active Definitive Interconnection System Impact Study prior to the Interconnection Facilities Study phase, that Interconnection Customer’s study cost obligation shall be equal to two (2) times its actual allocated cost of the Definitive Interconnection System Impact Study. If the Interconnection Customer’s study cost obligation as defined above exceeds the deposited amount submitted pursuant to Section 8.2, then the Interconnection Customer will be responsible for this excess cost. If the Interconnection Customer’s study cost obligation as defined above is less than the deposited amount submitted pursuant to Section 8.2, the difference shall be refunded to the Interconnection Customer.

8.6 Meeting with Transmission Provider.

Within ten (10) Business Days of providing a Definitive Interconnection System Impact Study report to Interconnection Customer, Transmission Provider, Transmission Owner and Interconnection Customer shall meet to discuss the results of the Definitive Interconnection System Impact Study.

8.7 Interconnection Requests That Require Previously Approved Network Upgrades.

At the completion of the Definitive Interconnection System Impact Study, the Definitive Interconnection System Impact Study may identify one or more Network Upgrades previously approved for construction under Section VI of Attachment O of this Tariff (“Previously Approved Network Upgrade”) and required to be in-service prior to an Interconnection Customer’s Commercial Operation Date. If a Previously Approved Network Upgrade will not be in-service prior to the Interconnection Customer’s Commercial Operation Date, Interconnection Customer’s Commercial Operation Date may be extended for a maximum period of three (3) years pursuant to Section 4.4.4 to accommodate the in-service date for a Previously Approved Network Upgrade. If the three (3) year extension is not sufficient for a Previously Approved Network Upgrade to be placed into service prior to the Interconnection Customer’s Commercial Operation Date, the Interconnection Customer will not be tendered an Interconnection Facilities Study Agreement. The Transmission Provider shall tender a Limited Operation Interconnection Facilities Study Agreement in the
form of Appendix 4A to the Interconnection Customer. If the Interconnection Customer executes the Limited Operation Interconnection Facilities Study Agreement, the Interconnection Customer agrees to the following conditions for moving into the Interconnection Facilities Study:

a. The Generating Facility will be allowed to operate under Limited Operation in accordance with Section 8.4.3 before a Previously Approved Network Upgrade is placed into service;

b. The Interconnection Customer will meet all requirements of the GIP;

c. The Interconnection Customer will provide financial security and authorize engineering, procurement, and construction of its cost assigned Network Upgrades and interconnection facilities no later than thirty (30) days after the effective date of the GIA; and

d. If the Transmission Provider determines that an earlier in-service date for a Previously Approved Network Upgrade can reasonably be met, then:

1. If the Limited Operation Interconnection Facilities Study Agreement amount identified in Section 8.4.3 is less than seventy-five (75) percent of the requested Interconnection Service, then the Interconnection Customer shall pay the cost of placing a Previously Approved Network Upgrade into service at an earlier date; or

2. If the Limited Operation Interconnection Facilities Study Agreement amount identified in Section 8.4.3 is greater than or equal to seventy-five (75) percent of the requested Interconnection Service, then the Interconnection Customer may either accept Limited Operation until the scheduled in-service date of a Previously Approved Network Upgrade or pay the cost of placing a Previously Approved Network Upgrade into service at an earlier date.

If the Interconnection Customer declines to execute the Limited Operation Interconnection Facilities Study Agreement, the Interconnection Customer may either remain in the DISIS Queue, withdraw the Interconnection Request or request a reduction in the amount of interconnection capacity in Interconnection Customer’s Interconnection Request.

8.68 Re-Study.
If Re-Study of the Definitive Interconnection System Impact Study is required due to a higher queued or equal priority queued project dropping out of the queue, or a modification of a higher queued project subject to Section 4.4, or re-designation of the Point of Interconnection pursuant to Section 8.2, or more than one Interconnection Customer (with similar electrical impacts as determined by the Transmission Provider) meeting all requirements of the Interconnection Facilities Study Agreement, the Transmission Provider shall notify Interconnection Customer in writing. Such Re-Study shall take no longer than sixty (60) Calendar Days from the date of notice. Any cost of Re-Study, as reduced by deposit amounts retained for other Interconnection Customer(s) under Section 13.3.8.4.c, shall be borne by the Interconnection Customer(s) being re-studied. Restudies will not be required of the Definitive Interconnection System Impact Study “Cluster Scenario” as the “Cluster Scenario” will be automatically re-evaluated for every open season.

8.97 Interconnection Facilities Study Agreement.

Simultaneously with the delivery of the Definitive Interconnection System Impact Study to Interconnection Customer, Transmission Provider shall provide to Interconnection Customer an Interconnection Facilities Study Agreement in the form of Appendix 4 to this GIP or a Limited Operation Interconnection Facilities Study Agreement in the form of Appendix 4A to this GIP. The Interconnection Facilities Study Agreement and the Limited Operation Interconnection Facilities Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Interconnection Facilities Study. Within three (3) Business Days following the Definitive Interconnection System Impact Study results meeting, Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection Facilities Study. Interconnection Customer shall within thirty (30) Calendar Days after receipt, execute and provide to the Transmission Provider the Interconnection Facilities Study Agreement or the Limited Operation Interconnection Facilities Study Agreement, and deliver the executed Interconnection Facilities Study Agreement to Transmission Provider within thirty (30) Calendar Days after its receipt, together with the required technical data along with a security deposit equal to $3000/MW of the plant size. This security deposit is in addition to any amount provided in Section 8.2. This security deposit shall be applied as follows:

a. The security deposit is refundable if the Interconnection Request is withdrawn prior to the execution of a GIA or a request to file the GIA at the Commission unexecuted unless the following conditions exist:

1. the withdrawal of the Interconnection Request is determined by Transmission Provider to cause increased facility upgrade cost to any Interconnection Customer in the Interconnection Facilities Queue; and
2. The total Network Upgrade cost estimates in the Interconnection Facilities Study increased by less than twenty-five percent (25%) over the Network Upgrade cost estimates in the Definitive Interconnection System Impact Study for the withdrawing Interconnection Customer.

b. Following the execution of a GIA or the filing of an unexecuted GIA at the Commission, the security deposit shall be applied toward the cost of constructing any Network Upgrades and Interconnection Facilities identified in the GIA. Any remaining funds shall be refunded to the Interconnection Customer following the Commercial Operation Date or otherwise subject to terms of the GIA.

one of the following:

a. Letter of credit or payment of Interconnection Customer’s share of estimated Network Upgrades less any amounts provided under Section 8.2.g.i (refundable if GIA is not executed by Interconnection Customer). Letter of credit shall be provided pursuant to Attachment X of the Tariff; or

b. An executed contract (or comparable evidence) for the sale of electric energy or capacity from the Generating Facility; or

c. Statement signed by an officer or authorized agent of the Interconnection Customer attesting that the Generating Facility is included in an applicable state resource plan; or

d. Other information that the Transmission Provider deems to be reasonable evidence that the Generating Facility will qualify as a Designated Resource; or

e. Purchase Order for generating equipment specific to Queue Position or statement signed by an officer or authorized agent of the Interconnection Customer attesting that the Generating Facility is included to be supplied with turbines with a manufacturer’s blanket purchase agreement that Interconnection Customer is a party. This agreement shall be provided to Transmission Provider; or

f. Application for an air permit (if applicable); or

g. Filing a Notice of Proposed Construction or Alteration with the Federal Aviation Administration (if applicable).

8.108 Scope of Interconnection Facilities Study.

The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Definitive Interconnection System Impact Study in
accordance with Good Utility Practice to physically and electrically connect the
Generating Facility to the Transmission System. The Interconnection Facilities
Study shall also identify the electrical switching configuration of the connection
equipment, including, without limitation: the transformer, switchgear, meters,
and other station equipment; the nature and estimated cost of any Transmission
Owner's Interconnection Facilities and Network Upgrades necessary to
accomplish the interconnection; and an estimate of the time required to complete
the construction and installation of such facilities.

The Interconnection Facilities Study shall utilize results of the Facility Analysis
from the Definitive Interconnection System Impact Study performed in
accordance with Section 8.4.4.

8.119 Interconnection Facilities Study Procedures.

a. Transmission Provider shall coordinate the Interconnection Facilities
Study with any Affected System pursuant to Section 3.5 above. Transmission
Provider shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study. Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer within the following number of days after receipt of an executed Interconnection Facilities Study Agreement: ninety (90) Calendar Days, with no more than a +/- 20 percent cost estimate contained in the report.

b. At the request of Interconnection Customer or at any time Transmission
Provider determines that it will not meet the required time frame for
completing the Interconnection Facilities Study, Transmission Provider
shall notify Interconnection Customer as to the schedule status of the
Interconnection Facilities Study. If Transmission Provider is unable to
complete the Interconnection Facilities Study and issue a draft
Interconnection Facilities Study report within the time required, it shall
notify Interconnection Customer and provide an estimated completion date
and an explanation of the reasons why additional time is required.

c. Interconnection Customer may, within thirty (30) Calendar Days after
receipt of the draft report, provide written comments to Transmission
Provider, which Transmission Provider shall include in the final report. Transmission Provider shall issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. Transmission Provider may reasonably extend such fifteen-day period upon notice to Interconnection Customer if Interconnection Customer's comments require Transmission Provider to perform additional analyses or
make other significant modifications prior to the issuance of the final
Interconnection Facilities Report. Upon request, Transmission Provider
shall provide Interconnection Customer supporting documentation,
workpapers, and databases or data developed in the preparation of the
Interconnection Facilities Study, subject to confidentiality arrangements
consistent with Section 13.1.

d. Interconnection Customer’s study cost obligations and refunds shall be as
defined in Section 13.3 with the following exception. An Interconnection
Customer that withdraws during or after the completion of the
Interconnection Facilities Study will receive no refund unless the facilities
cost estimate from the Interconnection Facilities Study exceeds the
facilities cost estimate from the Definitive Interconnection System Impact
Study by twenty-five percent (25%) or more. In such case, the
Interconnection Customer’s study cost obligation shall be equal to two (2)
times its actual allocated costs of such Definitive Interconnection System
Impact Study and Interconnection Facilities Study. If the Interconnection
Customer’s study cost obligation as defined above exceeds the deposited
amount submitted pursuant to Section 8.2, then the Interconnection
Customer will be responsible for this excess cost. If the Interconnection
Customer’s study cost obligation as defined above is less than the
deposited amount submitted pursuant to Section 8.2, the difference shall
be refunded to the Interconnection Customer.

8.120 Meeting with Transmission Provider.

Within ten (10) Business Days of providing a draft Interconnection Facilities
Study report to Interconnection Customer, Transmission Provider, Transmission
Owner and Interconnection Customer shall meet to discuss the results of the
Interconnection Facilities Study.

8.134 Re-Study.

If Re-Study of the Interconnection Facilities Study is required due to a higher or
equal priority queued project dropping out of the queue or a modification of a
higher queued project pursuant to Section 4.4, Transmission Provider shall so
notify Interconnection Customer in writing. Such Re-Study shall take no longer
than sixty (60) Calendar Days from the date of notice. Any cost of Re-Study, as
reduced by deposit amounts retained under Section 13.38.9.d, shall be borne by
the Interconnection Customer(s) being re-studied.
Section 9. Engineering & Procurement ('E&P') Agreement

Prior to executing a GIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request and Transmission Owner shall offer the Interconnection Customer, an E&P Agreement that authorizes Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, Transmission Owner shall not be obligated to offer an E&P Agreement if Interconnection Customer is in Dispute Resolution as a result of an allegation that Interconnection Customer has failed to meet any milestones or comply with any prerequisites specified in other parts of the GIP. The E&P Agreement is an optional procedure and it will not alter the Interconnection Customer's Interconnection Queue Position or In-Service Date. The E&P Agreement shall provide for Interconnection Customer to pay the cost of all activities authorized by Interconnection Customer and to make advance payments or provide other satisfactory security for such costs.

Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If Interconnection Customer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, Transmission Owner may elect: (i) to take title to the equipment, in which event Transmission Owner shall refund Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment, or (ii) to transfer title to and deliver such equipment to Interconnection Customer, in which event Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.
Section 10. Reserved
Section 11. Generator Interconnection Agreement (GIA)

11.1 Tender.

Interconnection Customer shall tender comments on the draft Interconnection Facilities Study report within thirty (30) Calendar Days of receipt of the report. Simultaneously with issuance of the final Interconnection Facilities Study report, the Transmission Provider shall tender to the Interconnection Customer a draft GIA together with draft appendices. The draft GIA shall be in the form of the Transmission Provider’s FERC-approved standard form GIA, which is in Appendix 6. The Transmission Provider, Transmission Owner and the Interconnection Customer shall negotiate concerning provisions of the appendices to the draft GIA for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study report.

11.2 Negotiation.

Notwithstanding Section 11.1, at the request of Interconnection Customer, Transmission Provider and the Transmission Owner shall begin negotiations with Interconnection Customer concerning the appendices to the GIA at any time after Interconnection Customer executes the Interconnection Facilities Study Agreement. Transmission Provider, Transmission Owner and Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft GIA for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study report. If Interconnection Customer determines that negotiations are at an impasse, it may request termination of the negotiations at any time after tender of the draft GIA pursuant to Section 11.1 and request submission of the unexecuted GIA with FERC or initiate Dispute Resolution procedures pursuant to Section 13.5. If Interconnection Customer requests termination of the negotiations, but within sixty (60) Calendar Days thereafter fails to request either the filing of the unexecuted GIA or initiate Dispute Resolution, it shall be deemed to have withdrawn its Interconnection Request. Unless otherwise agreed by the Parties, if Interconnection Customer has not executed the GIA, requested filing of an unexecuted GIA, or initiated Dispute Resolution procedures pursuant to Section 13.5 within sixty (60) Calendar Days of tender of draft GIA appendices, it shall be deemed to have withdrawn its Interconnection Request. Transmission Provider shall provide to Interconnection Customer a final GIA within fifteen (15) Business Days after the completion of the negotiation process.

11.3 Execution and Filing.

Within fifteen (15) Business Days after receipt of the final GIA, Interconnection Customer shall provide Transmission Provider (A) reasonable evidence of continued Site Control or (B) posting of $250,000, non-refundable additional security, which shall be applied toward future construction costs. At the same time, Interconnection Customer also shall provide reasonable evidence that one or
more of the following milestones in the development of the Generating Facility, at Interconnection Customer election, has been achieved: (i) the execution of a contract for the supply or transportation of fuel to the Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Generating Facility; (iv) execution of a contract (or comparable evidence) for the sale of electric energy or capacity from the Generating Facility; (v) statement signed by an officer or authorized agent of the Interconnection Customer attesting the Generating Facility is included in an applicable state resource plan; (vi) other information that the Transmission Provider deems to be reasonable evidence that the Generating Facility will qualify as a Designated Resource; or (vii) application for an air, water, or land use permit. The Transmission Provider will not execute the final Generator Interconnection Agreement unless the Interconnection Customer provides the information described in this paragraph.

Within fifteen (15) Business Days after receipt of the final GIA, the Interconnection Customer shall either: (i) execute three originals of the tendered GIA and return them to Transmission Owner who will execute them and forward them to the Transmission Provider; or (ii) request in writing that Transmission Provider file with FERC a GIA in unexecuted form. As soon as practicable, but not later than thirty (30) Calendar Business Days after receiving either the three executed originals of the tendered GIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or ten (10) Business Days after receiving the request to file an unexecuted GIA, Transmission Provider shall file the GIA with FERC, together with its explanation of any matters as to which Interconnection Customer, Transmission Owner and Transmission Provider disagree and support for the costs that Transmission Provider and/or the Transmission Owner propose to charge to Interconnection Customer under the GIA. An unexecuted GIA should contain terms and conditions deemed appropriate by Transmission Provider and the Transmission Owner for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted GIA, they may proceed pending FERC action.

11.4 Commencement of Interconnection Activities.

If Interconnection Customer executes the final GIA, Transmission Provider, the Transmission Owner and Interconnection Customer shall perform their respective obligations in accordance with the terms of the GIA, subject to modification by FERC. Upon submission of an unexecuted GIA, Interconnection Customer, Transmission Owner and Transmission Provider shall promptly comply with the unexecuted GIA, subject to modification by FERC.
Section 11A. Interim Generator Interconnection Agreement (Interim GIA)

11A.1 Availability.

Interconnection Customers with pending Interconnection Requests relating to Generating Facilities that have anticipated In-Service Dates prior to the expected completion of the Interconnection Studies pursuant to this Attachment V may request Interim Interconnection Service, execute an Interim Generator Interconnection Agreement (Interim GIA) and receive Interim Interconnection Service pursuant to the terms and conditions of this Section 11A and the Interim GIA. Execution of an Interim GIA and receipt of Interim Interconnection Service is an optional procedure and will not alter the Interconnection Customer’s Interconnection Queue Position. Interim Interconnection Service may be terminated at any point that a Generating Facility with an Interconnection Request that has a higher Interconnection Queue Position goes into Commercial Operation and Transmission Provider determines that Interim Interconnection Service and Interconnection Service cannot be provided to more than one Interconnection Customer simultaneously.

11A.2 Eligibility.

Interconnection Customers shall be eligible for Interim Interconnection Service under the following conditions:

11A.2.1 Interconnection Customer has provided Transmission Provider: (i) reasonable evidence of continued Site Control or posting of $250,000, non-refundable additional security, which shall be applied toward future construction costs; and (ii) reasonable evidence that one or more of the following milestones in the development of the Generating Facility, at Interconnection Customer election, has been achieved: (a) the execution of a contract for the supply or transportation of fuel to the Generating Facility; (b) the execution of a contract for the supply of cooling water to the Generating Facility; (c) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Generating Facility; (d) execution of a contract (or comparable evidence) for the sale of electric energy or capacity from the Generating Facility; (e) statement signed by an officer or authorized agent of the Interconnection Customer attesting the Generating Facility is included in an applicable state resource plan; (f) other information that the Transmission Provider deems to be reasonable evidence that the Generating Facility will qualify as a Designated Resource; or (g) application for an air, water, or land use permit. The Transmission Provider will not execute the Interim Generator Interconnection Agreement unless the Interconnection Customer provides the information described in this paragraph.
11A.2.2 Interconnection Customer has met the terms and conditions to be included in Transmission Provider’s Definitive Interconnection System Impact Study Queue pursuant to Section 8.2;

11A.2.3 Interconnection Customer has submitted in writing to Transmission Provider a request for Interim Interconnection Service;

11A.2.4 Interconnection Customer has entered into a study agreement pursuant to which it has agreed to pay all costs, including deposits for any additional studies deemed necessary by Transmission Provider to evaluate the feasibility of the Interconnection Customer’s requested Interim Interconnection Service;

11A.2.4.1 The Interim Availability Interconnection System Impact Study will maintain the scope and procedures of the Definitive Interconnection System Impact Study with the exception that certain previous queued Interconnection Requests may not be included in the study. Such exceptions and reasons for those exceptions will be noted in the study.

11A.2.4.2 The cost of the Interim Availability Interconnection System Impact Study will be subtracted from the Customer’s deposit submitted for the Definitive Interconnection System Impact Study.

11A.2.5 Transmission Provider has determined based upon the results of the additional studies, taking into account the Interconnection Customer’s In-Service Date and the Transmission System topology upon such date that there will be sufficient stability and reliability margin to accommodate Interim Interconnection Service to the Interconnection Customer’s Generating Facility;

11A.2.6 Interconnection Customer has executed an Interim GIA in accordance with Section 11A.3; and

11A.2.7 Interconnection Customer has provided security in accordance with Article 11.5 of the Interim GIA.

11A.3 Tender, Negotiation, Execution and Filing of Interim GIA.

11A.3.1 Upon completion of Transmission Provider’s analysis referenced in Section 11A.2.5, Transmission Provider shall notify Interconnection Customer in writing whether Interim Interconnection Service is feasible. In the event that Interconnection Customer’s requested Interim Interconnection Service is feasible, Transmission Provider shall tender to the Interconnection Customer a draft Interim GIA together with
appendices. The draft Interim GIA shall be in the form of the Transmission Provider's FERC-approved standard form Interim GIA, which is in Appendix 8.

11A.3.2 Transmission Provider, Transmission Owner and Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft Interim GIA for not more than thirty (30) Calendar Days after tender of the draft Interim GIA, unless another time period is agreed upon by the Parties. At the conclusion of the negotiation period or sooner if the Parties have reached agreement, Transmission Provider shall tender a final Interim GIA and within ten (10) Calendar Days the Interconnection Customer shall either: (i) execute three originals of the tendered Interim GIA and return them to Transmission Owner who will execute them and forward them to the Transmission Provider; or (ii) request in writing that Transmission Provider file with FERC an Interim GIA in unexecuted form. As soon as practicable, but not later than ten thirty (430) Calendar Business Days after receiving either the three executed originals of the tendered Interim GIA (if it does not conform with a FERC-approved standard form of interim interconnection agreement) or ten (10) Business Days after receiving the request to file an unexecuted Interim GIA, Transmission Provider shall file the Interim GIA with FERC, together with its explanation of any matters as to which Interconnection Customer, Transmission Owner and Transmission Provider disagree and support for the costs that Transmission Provider and/or the Transmission Owner propose to charge to Interconnection Customer under the Interim GIA. An unexecuted Interim GIA should contain terms and conditions deemed appropriate by Transmission Provider and the Transmission Owner for the Interconnection Request. Prior to FERC action, the Parties may agree to proceed with design, procurement, and construction of facilities and upgrades under the terms of the unexecuted Interim GIA.

11A.4 Commencement of Interim Interconnection Activities.

If Interconnection Customer executes the Interim GIA, Transmission Provider, the Transmission Owner and Interconnection Customer shall perform their respective obligations in accordance with the terms of the Interim GIA, subject to modification by FERC. Upon submission of an unexecuted Interim GIA, Interconnection Customer, Transmission Owner and Transmission Provider shall promptly comply with the unexecuted Interim GIA, subject to modification by FERC.

11A.5 Interconnection Service upon Termination of Interim GIA.
Terminating events for an Interim GIA are given in Article 2.3.1 of the Interim GIA. Upon termination of the Interim GIA for any reason, the Interim Interconnection Service shall cease. Interconnection Service, if any, associated with the Generating Facility shall be provided to Interconnection Customer by Transmission Provider pursuant to the terms and conditions of a final GIA.
Section 12. Construction of Interconnection Facilities and Network Upgrades

12.1 Schedule.

Transmission Provider, the Transmission Owner and Interconnection Customer shall negotiate in good faith concerning a schedule for the construction of Transmission Owner's Interconnection Facilities and the Network Upgrades.

12.2 Construction Sequencing of Transmission Owner’s Interconnection Facilities, Network Upgrades and Distribution Upgrades.

12.2.1 General.

In general, the In-Service Date of an Interconnection Customer seeking interconnection to the Transmission System will determine the sequence of construction of Interconnection Facilities, Network Upgrades and Distribution Upgrades.

12.2.2 Advance Construction of Network Upgrades that are an Obligation of an Entity other than Interconnection Customer.

An Interconnection Customer with a GIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) were assumed in the Interconnection Studies for such Interconnection Customer, (ii) are necessary to support such In-Service Date, and (iii) would otherwise not be completed, pursuant to a contractual obligation of an entity other than Interconnection Customer that is seeking interconnection to the Transmission System, in time to support such In-Service Date. Upon such request, Transmission Owner will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Owner: (i) any associated expediting costs and (ii) the cost of such Network Upgrades.

Transmission Provider will refund to Interconnection Customer both the expediting costs and the cost of Network Upgrades, in accordance with Article 11.4 of the GIA. Consequently, the entity with a contractual obligation to construct such Network Upgrades shall be obligated to pay only that portion of the costs of the Network Upgrades that Transmission Provider has not refunded to Interconnection Customer. Payment by that entity shall be due on the date that it would have been due had there been no request for advance construction. Transmission Provider shall forward to Interconnection Customer the amount paid by the entity with a contractual obligation to construct the Network Upgrades as payment in full for the outstanding balance owed to Interconnection Customer. Transmission Provider then shall refund to that entity the amount that it
paid for the Network Upgrades, in accordance with Article 11.4 of the GIA.

12.2.3 Advancing Construction of Network Upgrades that are Part of an Expansion Plan of the Transmission Provider.

An Interconnection Customer with a GIA, in order to maintain its In-Service Date, may request that Transmission Owner advance to the extent necessary the completion of Network Upgrades that: (i) are necessary to support such In-Service Date and (ii) would otherwise not be completed, pursuant to an expansion plan of Transmission Provider, in time to support such In-Service Date. Upon such request, Transmission Owner will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Owner any associated expediting costs.

12.2.4 Amended Definitive Interconnection System Impact Study.

A Definitive Interconnection System Impact Study will be amended to determine the facilities necessary to support the requested In-Service Date. This amended study will include those transmission and Generating Facilities that are expected to be in service on or before the requested In-Service Date.

12.3 Upgrades which will not be constructed by Transmission Owner.

For all interconnection agreements that identify Network Upgrades and Distribution Upgrades as listed in Appendix A of the GIA which are required to be built by an entity other than the Transmission Owner (as defined in this Attachment V), such upgrades shall be constructed in accordance with the process defined under Section VI of Attachment O to the SPP Tariff.
Section 13. Miscellaneous

13.1 Confidentiality.

Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of a GIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

13.1.1 Scope.

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of the GIA; or (6) is required, in accordance with Section 13.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the GIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

13.1.2 Release of Confidential Information.

Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of
Interconnection Customer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this Section 13.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 13.1.

13.1.3 Rights.

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

13.1.4 No Warranties.

By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

13.1.5 Standard of Care.

Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under these procedures or its regulatory requirements.

13.1.6 Order of Disclosure.

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of the GIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.
13.1.7 Remedies.

The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Section 13.1. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Section 13.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Section 13.1, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 13.1.

13.1.8 Disclosure to FERC, its Staff, or a State.

Notwithstanding anything in this Section 13.1 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the GIP, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR Section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the GIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR Section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, consistent with applicable state rules and regulations.

13.1.9 Subject to the exception in Section 13.1.8, any information that a Party claims is competitively sensitive, commercial or financial information ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be
unreasonably withheld; or (iv) necessary to fulfill its obligations under this GIP or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a subregional, regional or national reliability organization or planning group. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

13.1.10 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

13.1.11 Transmission Provider shall, at Interconnection Customer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.

13.2 Delegation of Responsibility.

Transmission Provider may use the services of subcontractors as it deems appropriate to perform its obligations under this GIP. Transmission Provider shall remain primarily liable to Interconnection Customer for the performance of such subcontractors and compliance with its obligations of this GIP. The subcontractor shall keep all information provided confidential and shall use such information solely for the performance of such obligation for which it was provided and no other purpose.

13.3 Obligation for Study Costs.

Except as provided below, in Section 8.4.c and Section 8.9.d, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Studies. Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded, except as otherwise provided herein, to Interconnection Customer or offset against the cost of any future Interconnection Studies associated with the applicable Interconnection Request prior to beginning of any such future Interconnection Studies. Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study. Interconnection Customer shall pay any such undisputed costs within thirty (30) Calendar Days of receipt of an invoice therefore. Transmission Provider shall not be obligated to perform or continue to perform any studies unless Interconnection Customer has paid all undisputed amounts in compliance herewith. **Milestone**
deposits collected in Sections 8.2 and 8.9 may also be used to pay the study costs for any restudies in accordance with Section 8.13 that affect lower-queued Interconnection Customers.

Unused study deposits provided pursuant to Section 8.2 will be refunded upon Commercial Operation. In the event that the Interconnection Customer withdraws its Interconnection Request during or after the Interconnection Facilities Study phase or terminates or suspends its interconnection agreement, Transmission Provider shall refund to Interconnection Customer such unused study deposits, less any costs associated with any studies or restudies required as a result of the withdrawal of the Interconnection Request or suspension or termination of the interconnection agreement, including any restudies associated with any affected lower-queued customers.

13.4 Third Parties Conducting Studies.

If (i) at the time of the signing of an Interconnection Study Agreement there is disagreement as to the estimated time to complete an Interconnection Study, (ii) Interconnection Customer receives notice pursuant to Sections 6.3, 7.4 or 8.5 that Transmission Provider will not complete an Interconnection Study within the applicable timeframe for such Interconnection Study, or (iii) Interconnection Customer receives neither the Interconnection Study nor a notice under Sections 6.3, 7.4 or 8.5 within the applicable timeframe for such Interconnection Study, then Interconnection Customer may require Transmission Provider to utilize a third party consultant reasonably acceptable to Interconnection Customer and Transmission Provider to perform such Interconnection Study under the direction of Transmission Provider. At other times, Transmission Provider may also utilize a third party consultant to perform such Interconnection Study, either in response to a general request of Interconnection Customer, or on its own volition.

In all cases, use of a third party consultant shall be in accord with Article 26 of the GIA (Subcontractors) and limited to situations where Transmission Provider determines that doing so will help maintain or accelerate the study process for Interconnection Customer's pending Interconnection Request and not interfere with Transmission Provider's progress on Interconnection Studies for other pending Interconnection Requests. In cases where Interconnection Customer requests use of a third party consultant to perform such Interconnection Study, Interconnection Customer and Transmission Provider shall negotiate all of the pertinent terms and conditions, including reimbursement arrangements and the estimated study completion date and study review deadline. Transmission Provider shall convey all workpapers, data bases, study results and all other supporting documentation prepared to date with respect to the Interconnection Request as soon as practicable upon Interconnection Customer's request subject to the confidentiality provision in Section 13.1. In any case, such third party contract may be entered into with either Interconnection Customer or Transmission Provider at Transmission Provider's discretion. In the case of (iii) Interconnection Customer maintains its right to submit a claim to Dispute
Resolution to recover the costs of such third party study. Such third party consultant shall be required to comply with this GIP, Article 26 of the GIA (Subcontractors), and the relevant Tariff procedures and protocols as would apply if Transmission Provider were to conduct the Interconnection Study and shall use the information provided to it solely for purposes of performing such services and for no other purposes. Transmission Provider shall cooperate with such third party consultant and Interconnection Customer to complete and issue the Interconnection Study in the shortest reasonable time.

13.5 Disputes.

In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with the GIP, or their performance, the Parties agree to resolve such dispute using the dispute resolution procedures in Section 12 of the Tariff.

13.6 Local Furnishing Bonds.

13.6.1 Transmission Owners That Own Facilities Financed by Local Furnishing or Other Tax-Exempt Bonds or That Are Tax Exempt Entities.

This provision is applicable only to a Transmission Owner that has financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds") or facilities with other bonds the interest on which is excluded from gross income under Section 103 of the Internal Revenue Code ("other tax-exempt bonds"), or that are tax-exempt entities, described in Section 501(c) of the Internal Revenue Code. Notwithstanding any other provision of this GIA and GIP, Transmission Provider shall not be required to provide Interconnection Service to Interconnection Customer pursuant to this GIA and GIP if the provision of such Interconnection Service would jeopardize the tax-exempt status of any local furnishing bond(s) or other tax-exempt bonds used to finance a Transmission Owner’s facilities that would be used in providing such Interconnection Service or would jeopardize the tax-exempt status of the transmission entity.

13.6.2 Alternative Procedures for Requesting Interconnection Service.

If Transmission Provider determines that the provision of Interconnection Service requested by Interconnection Customer would jeopardize the tax-exempt status of any local furnishing bond(s) or other tax-exempt bonds used to finance a Transmission Owner’s facilities that would be used in providing such Interconnection Service or would jeopardize the tax-exempt status of the Transmission Owner, Transmission Provider shall
advise the Interconnection Customer within thirty (30) Calendar days of receipt of the Interconnection Request.

Interconnection Customer thereafter may renew its request for interconnection using the process specified in Article 5.2(ii) of the Transmission Provider’s Tariff.
Section 14. Fast Track Process

14.1 Applicability
The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission System if the Small Generating Facility is no larger than 2 MW and if the Interconnection Customer's proposed Small Generating Facility meets the codes, standards, and certification requirements of Appendices 9 and 10 of these procedures, or the Transmission Owner has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

14.2 Initial Review
Interconnection Customer shall submit an application in the form of Appendix 1 along with a deposit of $1000. Within 15 Business Days after the Transmission Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the Transmission Provider shall have the Transmission Owner perform an initial review using the screens set forth below. The Transmission Provider shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Transmission Owner’s determinations under the screens.

14.2.1 Screens

14.2.1.1 The proposed Small Generating Facility’s Point of Interconnection must be on a portion of the Distribution System that is subject to the Tariff.

14.2.1.2 For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Transmission Owner’s electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

14.2.1.3 For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW.

14.2.1.4 The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.
14.2.1.5 The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

14.2.1.6 Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Transmission Owner’s electric power system due to a loss of ground during the operating time of any anti-islanding function.

<table>
<thead>
<tr>
<th>Primary Distribution Line Type</th>
<th>Type of Interconnection to Primary Distribution Line</th>
<th>Result/Criteria</th>
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<tbody>
<tr>
<td>Three-phase, three wire</td>
<td>3-phase or single phase, phase-to-phase</td>
<td>Pass screen</td>
</tr>
<tr>
<td>Three-phase, four wire</td>
<td>Effectively-grounded 3 phase or Single-phase, line-to-neutral</td>
<td>Pass screen</td>
</tr>
</tbody>
</table>

14.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

14.2.1.8 If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

14.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

14.2.1.10 No construction of facilities by the Transmission Provider on its own system shall be required to accommodate the Small Generating Facility.
14.2.1.11 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

14.2.1.12 The Interconnection Customer must pay any study costs that exceed the deposit without interest within thirty (30) calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within thirty (30) calendar days of the invoice without interest.

14.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved and the Transmission Provider will provide the Interconnection Customer a draft GIA within five Business Days after the determination that requires the Interconnection customer to pay the costs of such system modifications prior to interconnection. Interconnection Customer and Transmission Owner shall complete negotiation of the GIA as described in Section 14.2.4.

14.2.3 If the proposed interconnection fails the screens, but both the Transmission Provider and the Transmission Owner determine that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Transmission Provider shall provide the Interconnection Customer a draft GIA within five Business Days after the determination that requires the Interconnection customer to pay the costs of such system modifications prior to interconnection. Interconnection Customer and Transmission Owner shall complete negotiation of the GIA as described in Section 14.2.4.

14.2.4 After receiving a draft GIA from the Transmission Provider, the Interconnection Customer and the Transmission Owner shall have 30 Business Days or another mutually agreeable timeframe to sign and return the GIA, or request that the Transmission Provider file an unexecuted GIA with the Federal Energy Regulatory Commission. If the Interconnection Customer does not sign the GIA, or ask that it be filed unexecuted by the Transmission Provider within 30 Business Days, the Interconnection Request shall be deemed withdrawn. After the GIA is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the GIA.

14.2.5 If the proposed interconnection fails the screens, but the Transmission Provider and Transmission Owner do not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the
Transmission Provider shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

14.3 Customer Options Meeting
If the Transmission Provider determines the Interconnection Request cannot be approved without minor modifications at minimal cost; or a supplemental study or other additional studies or actions; or at significant cost to address safety, reliability, or power quality problems, within the five Business Day period after the determination, the Transmission Provider shall notify the Interconnection Customer and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the Transmission Provider's determination, the Transmission Provider shall offer to convene a customer options meeting with the Transmission Provider and the Transmission Owner to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the Transmission Provider's determination, or at the customer options meeting, the Transmission Provider/Transmission Owner shall:

14.3.1 Offer to perform facility modifications or minor modifications to the Transmission Owner’s electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Transmission Owner’s electric system; or

14.3.2 Offer to perform a supplemental review if the Transmission Provider concludes that the supplemental review might determine that the Small Generating Facility could continue to qualify for interconnection pursuant to the Fast Track Process, and provide a non-binding good faith estimate of the costs of such review; or

14.3.3 Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under Sections 2-13.

14.4 Supplemental Review
If the Interconnection Customer agrees to a supplemental review, the Interconnection Customer shall agree in writing within 15 Business Days of the offer, and submit a deposit for the estimated costs. The Interconnection Customer shall be responsible for the Transmission Provider's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 30 calendar days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Transmission Provider will return such excess within 30 calendar days of the invoice without interest.

14.4.1 Within ten Business Days following receipt of the deposit for a supplemental review, the Transmission Provider will determine if the Small Generating Facility can be interconnected safely and reliably.

14.4.1.1 If so, the Transmission Provider shall forward a draft GIA to the Interconnection Customer within five Business Days that requires
the Interconnection Customer to pay the costs of such system modifications prior to interconnection. Interconnection Customer and Transmission Owner shall complete negotiation of the GIA as described in Section 14.2.4.

14.4.1.2 If so, and Interconnection Customer facility modifications are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Transmission Provider shall forward a draft GIA to the Interconnection Customer within five Business Days after confirmation that the Interconnection Customer has agreed to make the necessary changes at the Interconnection Customer's cost. Interconnection Customer and Transmission Owner shall complete negotiation of the GIA described in Section 14.2.4.

14.4.1.3 If so, and minor modifications to the Transmission Owner’s electric system are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under the Fast Track Process, the Transmission Provider shall forward an executable GIA to the Interconnection Customer within ten Business Days that requires the Interconnection Customer to pay the costs of such system modifications prior to interconnection.

14.4.1.4 If not, the Interconnection Request will continue to be evaluated under Sections 2-13.
APPENDIX 1 TO GIP
INTERCONNECTION REQUEST FOR A GENERATING FACILITY

1. The undersigned Interconnection Customer submits this request to interconnect its Generating Facility with the Transmission System pursuant to the Tariff.

2. This Interconnection Request is for (check one):
   _____ A proposed new Generating Facility.
   _____ An increase in the generating capacity or a Material Modification of an existing Generating Facility.

3. The type of interconnection service requested (check one):
   _____ (MW)Energy Resource Interconnection Service
   _____ (MW)Network Resource Interconnection Service

4. _____ Check here only if Interconnection Customer requesting Network Resource Interconnection Service also seeks to have its Generating Facility studied for Energy Resource Interconnection Service

5. The Interconnection Customer provides the following information:
   a. Address or location or the proposed new Generating Facility site (to the extent known) or, in the case of an existing Generating Facility, the name and specific location of the existing Generating Facility;

   b. Maximum summer at _____ degrees C and winter at _____ degrees C megawatt electrical output of the proposed new Generating Facility or the amount of megawatt increase in the generating capacity of an existing Generating Facility;

   c. Preliminary one-line diagram of the Generating Facility;

   d. Commercial Operation Date (day, month, and year);

   e. Name, address, telephone number, and e-mail address of Interconnection Customer's contact person;

   f. Geographical map showing the approximate location of the proposed Point of Interconnection and the location of the Generating Facility; and

   g. Generating Facility Data (set forth in Attachment A to this Appendix 1)

6. Type of Interconnection Study requested and applicable deposit amount (check one).
   _____ Interconnection Feasibility Study – $10,000 deposit.
Preliminary Interconnection System Impact Study – $10,000 deposit.
Definitive Interconnection System Impact Study – $10,000 deposit.

7. Evidence of Site Control as specified in the GIP (check one)
   ___ Is attached to this Interconnection Request
   ___ Will be provided at a later date in accordance with this GIP (only applicable to Interconnection Feasibility Study)

8. This Interconnection Request shall be submitted to the representative indicated below:
   Manager, GI Studies
   Southwest Power Pool, Inc.
   201 Worthen Drive
   Little Rock, AR 72223-4936

9. Representative of Interconnection Customer to contact (including e-mail address):
   [To be completed by Interconnection Customer]

10. This Interconnection Request is submitted by:
    Name of Interconnection Customer: ________________________________
    By (signature): ________________________________
    Name (type or print): ________________________________
    Title: ________________________________
    Date: ________________________________
### GENERATING FACILITY DATA
#### FOR THE FEASIBILITY STUDY

#### UNIT RATINGS

<table>
<thead>
<tr>
<th>Nameplate kVA</th>
<th>°F</th>
<th>Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prime Mover type</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power Factor</td>
<td>Lead</td>
<td>Lag</td>
</tr>
<tr>
<td>Max Turbine Power Summer MW</td>
<td>F</td>
<td></td>
</tr>
<tr>
<td>Winter MW</td>
<td>F</td>
<td></td>
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</tbody>
</table>

#### GENERATOR STEP-UP TRANSFORMER DATA RATINGS

<table>
<thead>
<tr>
<th>Capacity</th>
<th>Self-cooled/</th>
<th>Maximum Nameplate</th>
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<tbody>
<tr>
<td>Voltage Ratio (Generator Side/System Side/Tertiary)</td>
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<td></td>
</tr>
<tr>
<td>Winding Connections (Low V/High V/Tertiary V (Delta or Wye))</td>
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<td></td>
</tr>
<tr>
<td>Fixed Taps Available</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Present Tap Setting</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Impedance Positive $Z_1$ (on self-cooled kVA rating)</td>
<td>%</td>
<td>X/R</td>
</tr>
<tr>
<td>Impedance Zero $Z_0$ (on self-cooled kVA rating)</td>
<td>%</td>
<td>X/R</td>
</tr>
</tbody>
</table>
APPENDIX 2 TO GIP

INTERCONNECTION FEASIBILITY STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____ day of ________ 20___ by and between __________________, a __________________ organized and existing under the laws of the State of __________________, ("Interconnection Customer") and Southwest Power Pool, Inc. a Corporation existing under the laws of the State of Arkansas, ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated ____________, and

WHEREAS, Interconnection Customer desires to interconnect the Generating Facility with the Transmission System; and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Generating Facility to the Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved GIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed an Interconnection Feasibility Study consistent with Section 6.0 of this GIP in accordance with the Tariff.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study shall be based on the technical information provided by Interconnection Customer in the Interconnection Request, as may be modified as the result of the Scoping Meeting. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with Section 3.3.4 of the GIP. If, after the designation of the Point of Interconnection pursuant to Section 3.3.4 of the GIP, Interconnection Customer modifies its Interconnection Request pursuant to Section 4.4, the time to complete the Interconnection Feasibility Study may be extended.
5.0 The Interconnection Feasibility Study report shall provide the following information:
- preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection; and
- preliminary description and non-binding estimated cost of facilities required to interconnect the Generating Facility to the Transmission System and to address the identified power flow issues.

6.0 The Interconnection Customer shall have provided the deposit(s) as specified under Section 6 of the GIP with the submission of the Interconnection Request and for the performance of the Interconnection Feasibility Study.

Upon receipt of the Interconnection Feasibility Study Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study.

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Governing Law

7.1 Governance. The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the United States of America except to the extent that the laws of the state of Arkansas may apply.

7.2 Applicability. This Agreement is subject to all applicable federal and state Laws and Regulations.

7.3 Reservation of Rights. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

8.0 Notices.

8.1 General. Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider:
To Interconnection Customer:

[Blank]

Attention: ______________________

8.2 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

9.0 Force Majeure

9.1 Economic Hardship. Economic hardship is not considered a Force Majeure event.

9.2 Default. Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 10), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

10.0 Indemnity

10.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other
Partys’ action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

10.1.1 **Indemnified Person.** If an indemnified person is entitled to indemnification under this Article 10 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 10.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

10.1.2 **Indemnifying Party.** If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 10, the amount owing to the indemnified person shall be the amount of such indemnified person’s actual Loss, net of any insurance or other recovery.

10.1.3 **Indemnity Procedures.** Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 10.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party.
Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

10.2 **Consequential Damages.** Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

11.0 **Assignment**

11.1 **Assignment.** This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party’s, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's
obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

12.0 Severability

12.1 Severability. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

13.0 Comparability

13.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

14.0 Deposits and Invoice Procedures

14.1 General. The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

14.2 Study Deposits. The Interconnection Customer shall provide study deposits, in accordance with the GIP to the Transmission Provider. The study deposits amounts and schedule shall be in accordance with the GIP.

14.3 Final Invoice. Within six months after completion of the studies Transmission Provider shall provide an invoice of the final cost of the studies and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

14.4 Payment. Invoices shall be rendered to the paying Party at the address specified in the Interconnection Request in Appendix 1 to the GIP. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under the GIP.
14.5 Disputes. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

15.0 Representations, Warranties, and Covenants

15.1 General. Each Party makes the following representations, warranties and covenants:

15.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

15.1.2 Authority. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

15.1.3 No Conflict. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.
15.1.4 **Consent and Approval.** Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

16.0 **Breach, Cure and Default**

16.1 **General.** A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe any material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with the provisions of Section 17.4.

16.2 **Events of Breach.** A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

16.3 **Cure and Default.** Upon the occurrence of an event of Breach, the Party not in Breach (hereinafter the “Non-Breaching Party”), when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party (the “Breaching Party”) and to any other person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days to cure such Breach. If
the Breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement.

16.4 Right to Compel Performance. Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

17. Miscellaneous

17.1 Binding Effect. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

17.2 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

17.3 Rules of Interpretation. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder.

17.4 Entire Agreement. This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of
the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

17.5 **No Third Party Beneficiaries.** This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

17.6 **Waiver.** The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.7 **Headings.** The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

17.8 **Multiple Counterparts.** This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

17.9 **Amendment.** The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

17.10 **Modification by the Parties.** The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

17.11 **No Partnership.** This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.
IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Southwest Power Pool, Inc.

By: ________________________ Title: ________________________
Date: ________________________  [Insert name of Interconnection Customer]

By: ________________________
Title: ________________________
Date: ________________________
ASSUMPTIONS USED IN CONDUCTING THE INTERCONNECTION FEASIBILITY STUDY

The Interconnection Feasibility Study will be based upon the information set forth in the Interconnection Request and agreed upon in the Scoping Meeting held on ________________

   Designation of Point of Interconnection and configuration to be studied.
   Designation of alternative Point(s) of Interconnection and configuration.

   [Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer and Transmission Provider]
APPENDIX 3 TO GIP

PRELIMINARY INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____ day of ___________ 20___ by and between ___________________ a ________________ and existing under the laws of the State of ___________________ ("Interconnection Customer") and Southwest Power Pool, Inc. a non-profit organization under the laws of the State of Arkansas ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ______________; and

WHEREAS, Interconnection Customer desires to interconnect the Generating Facility with the Transmission System;

WHEREAS, Transmission Provider has completed an Interconnection Feasibility Study (the "Feasibility Study") and provided the results of said study to Interconnection Customer (This recital to be omitted if Transmission Provider or Interconnection Customer does not require the Interconnection Feasibility Study.); and

WHEREAS, Interconnection Customer has requested Transmission Provider to perform a Preliminary Interconnection System Impact Study to assess the impact of interconnecting the Generating Facility to the Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved GIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed a Preliminary Interconnection System Impact Study consistent with Section 7.0 of this GIP in accordance with the Tariff.

3.0 The scope of the Preliminary Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Preliminary Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study (if performed) and the technical information provided by Interconnection Customer in the Interconnection Request, subject to any modifications in accordance with Section 4.4 of the GIP. Transmission Provider reserves the right to request additional technical
information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Preliminary Interconnection System Impact Study. If Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the Preliminary Interconnection System Impact Study may be extended.

5.0 The Preliminary Interconnection System Impact Study report shall provide the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- identification of any thermal overload or voltage limit violations resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection and

- description and non-binding, good faith estimated cost of facilities required to interconnect the Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues.

6.0 Interconnection Customer shall provide the deposit specified under Section 7.2 of the GIP for the performance of the Preliminary Interconnection System Impact Study. Transmission Provider's good faith estimate for the time of completion of the Preliminary Interconnection System Impact Study is [insert date].

Upon receipt of the Preliminary Interconnection System Impact Study results, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Preliminary Interconnection System Impact Study.

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer in accordance with Section 7.2 of the GIP.

7.0 Governing Law

7.1 Governance. The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the United States of America except to the extent that the laws of the state of Arkansas may apply.

7.2 Applicability. This Agreement is subject to all applicable federal and state Laws and Regulations.
7.3 **Reservation of Rights.** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

8.0 **Notices.**

8.1 **General.** Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider: 

Southwest Power Pool, Inc. 
201 Worthen Drive 
Little Rock, AR 
Attention: Manager, GI Studies

To Interconnection Customer:

__________________________ 
__________________________ 
__________________________ 
Attention: ______________________

8.2 **Alternative Forms of Notice.** Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

9.0 **Force Majeure**

9.1 **Economic Hardship.** Economic hardship is not considered a Force Majeure event.

9.2 **Default.** Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 10), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by
telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

10.0 Indemnity

10.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

10.1.1 Indemnified Person. If an indemnified person is entitled to indemnification under this Article 10 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 10.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

10.1.2 Indemnifying Party. If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 10, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

10.1.3 Indemnity Procedures. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 10.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and
reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

10.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

11.0 Assignment

11.1 Assignment. This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this
Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party’s, trustee’s or mortgagee’s assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

12.0 Severability

12.1 Severability. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

13.0 Comparability

13.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

14.0 Deposits and Invoice Procedures

14.1 General. The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

14.2 Study Deposits. The Interconnection Customer shall provide study deposits, in accordance with the GIP to the Transmission Provider. The study deposits amounts and schedule shall be in accordance with the GIP.
14.3 **Final Invoice.** Within six months after completion of the studies Transmission Provider shall provide an invoice of the final cost of the studies and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

14.4 **Payment.** Invoices shall be rendered to the paying Party at the address specified in the Interconnection Request in Appendix 1 to the GIP. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under the GIP.

14.5 **Disputes.** In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC’s regulations at 18 CFR § 35.19a(a)(2)(iii).

15.0 **Representations, Warranties, and Covenants**

15.1 **General.** Each Party makes the following representations, warranties and covenants:

15.1.1 **Good Standing.** Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.
15.1.2 Authority. Such Party has the right, power and authority to enter into this Agreement, to become a party thereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

15.1.3 No Conflict. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

15.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

16.0 Breach, Cure and Default

16.1 General. A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe any material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with the provisions of Section 17.4.

16.2 Events of Breach. A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;
(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;
(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

16.3 Cure and Default. Upon the occurrence of an event of Breach, the Party not in Breach (hereinafter the “Non-Breaching Party”), when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party (the “Breaching Party”) and to any other person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days to cure such Breach. If the Breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement.

16.4 Right to Compel Performance. Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

17. Miscellaneous

17.1 Binding Effect. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

17.2 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

17.3 Rules of Interpretation. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes
such person's successors and assigns but, in the case of a Party, only if such
successors and assigns are permitted by this Agreement, and reference to a person
in a particular capacity excludes such person in any other capacity or individually;
(3) reference to any agreement (including this Agreement), document, instrument
or tariff means such agreement, document, instrument, or tariff as amended or
modified and in effect from time to time in accordance with the terms thereof and,
if applicable, the terms hereof; (4) reference to any Applicable Laws and
Regulations means such Applicable Laws and Regulations as amended, modified,
codified, or reenacted, in whole or in part, and in effect from time to time,
including, if applicable, rules and regulations promulgated thereunder.

17.4 Entire Agreement. This Agreement, including all Appendices and Schedules
attached hereto, constitutes the entire agreement between the Parties with
reference to the subject matter hereof, and supersedes all prior and
contemporaneous understandings or agreements, oral or written, between the
Parties with respect to the subject matter of this Agreement. There are no other
agreements, representations, warranties, or covenants that constitute any part of
the consideration for, or any condition to, either Party's compliance with its
obligations under this Agreement.

17.5 No Third Party Beneficiaries. This Agreement is not intended to and does not
create rights, remedies, or benefits of any character whatsoever in favor of any
persons, corporations, associations, or entities other than the Parties, and the
obligations herein assumed are solely for the use and benefit of the Parties, their
successors in interest and, where permitted, their assigns.

17.6 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon
strict performance of any provision of this Agreement will not be considered a
waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement
shall not be deemed a continuing waiver or a waiver with respect to any other
failure to comply with any other obligation, right, duty of this Agreement.
Termination or Default of this Agreement for any reason by Interconnection
Customer shall not constitute a waiver of Interconnection Customer's legal rights
to obtain an interconnection from Transmission Provider. Any waiver of this
Agreement shall, if requested, be provided in writing.

17.7 Headings. The descriptive headings of the various Articles of this Agreement
have been inserted for convenience of reference only and are of no significance in
the interpretation or construction of this Agreement.

17.8 Multiple Counterparts. This Agreement may be executed in two or more
counterparts, each of which is deemed an original but all constitute one and the
same instrument.
17.9 Amendment. The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

17.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

17.11 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

7.0 Miscellaneous. The Preliminary Interconnection System Impact Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, that are consistent with regional practices, Applicable Laws and Regulations and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the GIP and the GIA.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ___________________________   By: ___________________________
Title: ___________________________  Title: ___________________________
Date: ___________________________   Date: ___________________________

[Insert name of Interconnection Customer]

By: ___________________________
Title: ___________________________
Date: ___________________________
ASSUMPTIONS USED IN CONDUCTING THE
PRELIMINARY INTERCONNECTION SYSTEM IMPACT STUDY

The Preliminary Interconnection System Impact Study will be based upon the results of
the Interconnection Feasibility Study (if performed), subject to any modifications in accordance
with Section 4.4 of the GIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied.

Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by Interconnection Customer and other assumptions
to be provided by Interconnection Customer and Transmission Provider]

GENERATING FACILITY DATA FOR THE
PRELIMINARY INTERCONNECTION SYSTEM IMPACT STUDY

UNIT RATINGS

Nameplate kVA ___________ °F ________ Voltage ___________
Prime Mover type ____________________________
Power Factor: Lead _______ Lag _______
Speed (RPM) ___________ Connection (e.g. Wye) ____________
Short Circuit Ratio ___________ Frequency, Hertz ____________
Stator Amperes at Rated kVA ___________ Field Volts ___________
Max Turbine Power: Summer MW ___________ °F ______
                   Winter  MW ___________ °F ______

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = ___________________________ kW sec/kVA
Moment-of-Inertia, WR² = ___________________________ lb. ft.²

REACTANCE DATA (PER UNIT-RATED KVA)

DIRECT AXIS QUADRATURE AXIS

Synchronous – saturated X_{dv} _______ X_{qv} _______
### Synchronous – unsaturated
- \( X_{di} \)
- \( X_{qi} \)

### Transient – saturated
- \( X'_{dv} \)
- \( X'_{qv} \)

### Transient – unsaturated
- \( X'_{di} \)
- \( X'_{qi} \)

### Subtransient – saturated
- \( X''_{dv} \)
- \( X''_{qv} \)

### Subtransient – unsaturated
- \( X''_{di} \)
- \( X''_{qi} \)

### Negative Sequence – saturated
- \( X_{2v} \)

### Negative Sequence – unsaturated
- \( X_{2i} \)

### Zero Sequence – saturated
- \( X_{0v} \)

### Zero Sequence – unsaturated
- \( X_{0i} \)

### Leakage Reactance
- \( X_{lm} \)

### FIELD TIME CONSTANT DATA (SEC)

- Open Circuit: \( T'_{do} \) \( T'_{qo} \)
- Three-Phase Short Circuit Transient: \( T'_{d3} \) \( T'_{q} \)
- Line to Line Short Circuit Transient: \( T'_{d2} \)
- Line to Neutral Short Circuit Transient: \( T'_{d1} \)
- Short Circuit Subtransient: \( T''_{d} \) \( T''_{q} \)
- Open Circuit Subtransient: \( T''_{do} \) \( T''_{qo} \)

### ARMATURE TIME CONSTANT DATA (SEC)

- Three Phase Short Circuit: \( T_{a3} \)
- Line to Line Short Circuit: \( T_{a2} \)
- Line to Neutral Short Circuit: \( T_{a1} \)

NOTE: If requested information is not applicable, indicate by marking "N/A."

### MW CAPABILITY AND PLANT CONFIGURATION

### GENERATING FACILITY DATA

### ARMATURE WINDING RESISTANCE DATA (PER UNIT)

- Positive: \( R_{1} \)
- Negative: \( R_{2} \)
- Zero: \( R_{0} \)

Rotor Short Time Thermal Capacity \( I_{2}^{2}t = \)
Field Current at Rated kVA, Armature Voltage and PF = \( \) amps
Field Current at Rated kVA and Armature Voltage, 0 PF = \( \) amps
Three Phase Armature Winding Capacitance = _______ microfarad
Field Winding Resistance = _______ ohms _____ °C
Armature Winding Resistance (Per Phase) = _______ ohms _____ °C

CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

GENERATOR STEP-UP TRANSFORMER DATA RATINGS

Capacity  Self-cooled/
          Maximum Nameplate
____________/_______________kVA

Voltage Ratio (Generator Side/System side/Tertiary)
____________/_______________/_______________kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
____________/_______________/_____________

Fixed Taps Available _____________________________________________________

Present Tap Setting _______________________________________________________

Impedance: Positive   Z₁ (on self-cooled kVA rating)____________ % _______ X/R
Impedance: Zero       Z₀ (on self-cooled kVA rating)____________ % _______ X/R

EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.
WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request: ____________

Elevation: _______________     _____ Single Phase     _____ Three Phase

Inverter manufacturer, model name, number, and version: __________________________________________

List of adjustable setpoints for the protective equipment or software: __________________________________

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

INDUCTION GENERATORS

(*) Field Volts: ______________
(*) Field Amperes: _____________
(*) Motoring Power (kW): ________
(*) Neutral Grounding Resistor (If Applicable): ____________
(*) I²t or K (Heating Time Constant): ____________
(*) Rotor Resistance: __________
(*) Stator Resistance: __________
(*) Stator Reactance: ___________
(*) Rotor Reactance: ___________
(*) Magnetizing Reactance: ___________
(*) Short Circuit Reactance: ___________
(*) Exciting Current: ____________
(*) Temperature Rise: ___________
(*) Frame Size: ________________
(*) Design Letter: ______________
(*) Reactive Power Required In Vars (No Load): ___________
(*) Reactive Power Required In Vars (Full Load): ___________
(*) Total Rotating Inertia, H: _____ Per Unit on KVA Base

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required.
APPENDIX 3A TO GIP

DEFINITIVE INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____ day of ___________ 20___
by and between ___________________ a ________________ and existing under the laws of the
State of ___________________ ("Interconnection Customer") and Southwest Power Pool, Inc. a
non-profit organization under the laws of the State of Arkansas ("Transmission Provider ").
Interconnection Customer and Transmission Provider each may be referred to as a "Party," or
collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Generating Facility or
generating capacity addition to an existing Generating Facility consistent with the
Interconnection Request submitted by Interconnection Customer dated _________________; and

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with the Transmission System;

WHEREAS, Transmission Provider has completed a Preliminary Interconnection
System Impact Study and provided the results of said study to Interconnection Customer (This
recital to be omitted if Interconnection Customer did not participate in Preliminary
Interconnection System Impact Study); and

WHEREAS, Interconnection Customer has participated in a Preliminary Interconnection
System Impact Study and wishes to participate in the Definitive Interconnection System Impact
Study or has requested Transmission Provider to perform a Definitive Interconnection System
Impact Study to assess the impact of interconnecting the Generating Facility to the Transmission
System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained
herein the Parties agreed as follows:

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2.0 Interconnection Customer elects and Transmission Provider shall cause to be
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Section 7.0 of this GIP in accordance with the Tariff.

3.0 The scope of the Definitive Interconnection System Impact Study shall be subject
to the assumptions set forth in Attachment A to this Agreement.

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results of the Preliminary Interconnection System Impact Study and the technical
information provided by Interconnection Customer in the Interconnection
Request, subject to any modifications in accordance with Section 4.4 of the GIP.
Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Definitive Interconnection System Impact Study. If Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the Definitive Interconnection System Impact Study may be extended.

5.0 The Definitive Interconnection System Impact Study report shall provide the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- identification of any thermal overload or voltage limit violations resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection;

- description and non-binding, good faith estimated cost of facilities required to interconnect the Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues;

- will include a Facilities Analysis as specified in Section 8.4.4 that will provide cost estimates for Transmission Owner’s Interconnection Facilities and Network Upgrades at the Point of Interconnection.

6.0 Interconnection Customer shall provide the deposit specified under Section 8.2 of the GIP for the performance of the Definitive Interconnection System Impact Study. Transmission Provider's good faith estimate for the time of completion of the Definitive Interconnection System Impact Study is [insert date].

Upon receipt of the Definitive Interconnection System Impact Study results, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Definitive Interconnection System Impact Study.

Any difference between the deposit and Interconnection Customer’s study cost obligation shall be paid by or refunded to Interconnection Customer, as appropriate per Section 13.3 of the Generator Interconnection Procedures.

7.0 **Governing Law**

7.1 **Governance.** The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the United States of America except to the extent that the laws of the state of Arkansas may apply.
7.2 **Applicability.** This Agreement is subject to all applicable federal and state Laws and Regulations.

7.3 **Reservation of Rights.** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

8.0 **Notices.**

8.1 **General.** Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider:

Southwest Power Pool, Inc.

201 Worthen Drive

Little Rock, AR

Attention: Manager, GI Studies

To Interconnection Customer:

__________________________

__________________________

__________________________

Attention: ____________________

8.2 **Alternative Forms of Notice.** Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

9.0 **Force Majeure**

9.1 **Economic Hardship.** Economic hardship is not considered a Force Majeure event.

9.2 **Default.** Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 10), other than the obligation to pay money when due, if prevented from fulfilling such obligation by
Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

10.0 Indemnity

10.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

10.1.1 Indemnified Person. If an indemnified person is entitled to indemnification under this Article 10 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 10.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

10.1.2 Indemnifying Party. If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 10, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

10.1.3 Indemnity Procedures. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 10.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.
The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

10.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

11.0 Assignment
11.1 Assignment. This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party’s, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

12.0 Severability

12.1 Severability. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

13.0 Comparability

13.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

14.0 Deposits and Invoice Procedures

14.1 General. The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

14.2 Study Deposits. The Interconnection Customer shall provide study deposits, in accordance with the GIP to the Transmission Provider. The study deposits amounts and schedule shall be in accordance with the GIP.
14.3 **Final Invoice.** Within six months after completion of the studies Transmission Provider shall provide an invoice of the final cost of the studies and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

14.4 **Payment.** Invoices shall be rendered to the paying Party at the address specified in the Interconnection Request in Appendix 1 to the GIP. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under the GIP.

14.5 **Disputes.** In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

15.0 **Representations, Warranties, and Covenants**

15.1 **General.** Each Party makes the following representations, warranties and covenants:

15.1.1 **Good Standing.** Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.
15.1.2 Authority. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

15.1.3 No Conflict. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

15.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

16.0 Breach, Cure and Default

16.1 General. A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe any material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with the provisions of Section 17.4.

16.2 Events of Breach. A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;
(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

16.3 Cure and Default. Upon the occurrence of an event of Breach, the Party not in Breach (hereinafter the “Non-Breaching Party”), when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party (the “Breaching Party”) and to any other person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days to cure such Breach. If the Breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement.

16.4 Right to Compel Performance. Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

17. Miscellaneous

17.1 Binding Effect. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

17.2 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

17.3 Rules of Interpretation. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person...
in a particular capacity excludes such person in any other capacity or individually;
(3) reference to any agreement (including this Agreement), document, instrument
or tariff means such agreement, document, instrument, or tariff as amended or
modified and in effect from time to time in accordance with the terms thereof and,
if applicable, the terms hereof; (4) reference to any Applicable Laws and
Regulations means such Applicable Laws and Regulations as amended, modified,
codified, or reenacted, in whole or in part, and in effect from time to time,
including, if applicable, rules and regulations promulgated thereunder.

17.4 **Entire Agreement.** This Agreement, including all Appendices and Schedules
attached hereto, constitutes the entire agreement between the Parties with
reference to the subject matter hereof, and supersedes all prior and
contemporaneous understandings or agreements, oral or written, between the
Parties with respect to the subject matter of this Agreement. There are no other
agreements, representations, warranties, or covenants that constitute any part of
the consideration for, or any condition to, either Party's compliance with its
obligations under this Agreement.

17.5 **No Third Party Beneficiaries.** This Agreement is not intended to and does not
create rights, remedies, or benefits of any character whatsoever in favor of any
persons, corporations, associations, or entities other than the Parties, and the
obligations herein assumed are solely for the use and benefit of the Parties, their
successors in interest and, where permitted, their assigns.

17.6 **Waiver.** The failure of a Party to this Agreement to insist, on any occasion, upon
strict performance of any provision of this Agreement will not be considered a
waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement
shall not be deemed a continuing waiver or a waiver with respect to any other
failure to comply with any other obligation, right, duty of this Agreement.
Termination or Default of this Agreement for any reason by Interconnection
Customer shall not constitute a waiver of Interconnection Customer's legal rights
to obtain an interconnection from Transmission Provider. Any waiver of this
Agreement shall, if requested, be provided in writing.

17.7 **Headings.** The descriptive headings of the various Articles of this Agreement
have been inserted for convenience of reference only and are of no significance in
the interpretation or construction of this Agreement.

17.8 **Multiple Counterparts.** This Agreement may be executed in two or more
counterparts, each of which is deemed an original but all constitute one and the
same instrument.

17.9 **Amendment.** The Parties may by mutual agreement amend this Agreement by a
written instrument duly executed by the Parties.
17.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

17.11 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

Miscellaneous. The Definitive Interconnection System Impact Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, that are consistent with regional practices, Applicable Laws and Regulations and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the GIP and the GIA.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: _________________________ By: ______________________________
Title: _________________________ Title: ______________________________
Date: __________________________ Date: ______________________________

[Insert name of Interconnection Customer]

By: _________________________
Title: _________________________
Date: ______________________________
ASSUMPTIONS USED IN CONDUCTING THE DEFINITIVE INTERCONNECTION SYSTEM IMPACT STUDY

The Definitive Interconnection System Impact Study will be based upon the information set forth in the Interconnection Requests and results of applicable prior studies, subject to any modifications in accordance with Section 4.4 of the GIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied.

[Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer, Transmission Owner and Transmission Provider]

GENERATING FACILITY DATA FOR THE DEFINITIVE INTERCONNECTION SYSTEM IMPACT STUDY

UNIT RATINGS

Nameplate kVA _____________ °F _______ Voltage _____________
Prime Mover type _________________________
Power Factor: Lead _______ Lag _______
Speed (RPM) _____________ Connection (e.g. Wye) _____________
Short Circuit Ratio _____________ Frequency, Hertz _____________
Stator Amperes at Rated kVA _____________ Field Volts _____________
Max Turbine Power: Summer MW _____________ °F _______
Winter MW _____________ °F _______

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = ______________________ kW sec/kVA
Moment-of-Inertia, \( W R^2 = \) ______________________ lb. ft.²

REACTANCE DATA (PER UNIT-RATED KVA)

<table>
<thead>
<tr>
<th>DIRECT AXIS</th>
<th>QUADRATURE AXIS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Synchronous – saturated</td>
<td>( X_{dv} ) _______</td>
</tr>
<tr>
<td>Synchronous – unsaturated</td>
<td>( X_{di} ) _______</td>
</tr>
<tr>
<td>Transient – saturated</td>
<td>( X'_{dv} ) _______</td>
</tr>
<tr>
<td>Transient – unsaturated</td>
<td>( X'_{di} ) _______</td>
</tr>
</tbody>
</table>
Subtransient – saturated \( X_{dv} \) \( X_{qv} \)
Subtransient – unsaturated \( X_{di} \) \( X_{qi} \)
Negative Sequence – saturated \( X_{2v} \)
Negative Sequence – unsaturated \( X_{2i} \)
Zero Sequence – saturated \( X_{0v} \)
Zero Sequence – unsaturated \( X_{0i} \)
Leakage Reactance \( X_{lm} \)

FIELD TIME CONSTANT DATA (SEC)

Open Circuit \( T'_{do} \) \( T'_{qo} \)
Three-Phase Short Circuit Transient \( T'_{d3} \) \( T'_{q} \)
Line to Line Short Circuit Transient \( T'_{d2} \)
Line to Neutral Short Circuit Transient \( T'_{d1} \)
Short Circuit Subtransient \( T''_{d} \) \( T''_{q} \)
Open Circuit Subtransient \( T''_{do} \) \( T''_{qo} \)

ARMATURE TIME CONSTANT DATA (SEC)

Three Phase Short Circuit \( T_{a3} \)
Line to Line Short Circuit \( T_{a2} \)
Line to Neutral Short Circuit \( T_{a1} \)

NOTE: If requested information is not applicable, indicate by marking "N/A."

MW CAPABILITY AND PLANT CONFIGURATION
GENERATING FACILITY DATA

ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive \( R_1 \)
Negative \( R_2 \)
Zero \( R_0 \)

Rotor Short Time Thermal Capacity \( I_2^2 t = \) \[
\text{Field Current at Rated kVA, Armature Voltage and PF =} \quad \text{amps}
\text{Field Current at Rated kVA and Armature Voltage, 0 PF =} \quad \text{amps}
\text{Three Phase Armature Winding Capacitance =} \quad \text{microfarad}
\text{Field Winding Resistance =} \quad \text{ohms} \quad \text{°C}
\text{Armature Winding Resistance (Per Phase) =} \quad \text{ohms} \quad \text{°C}

600 of 851
CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

GENERATOR STEP-UP TRANSFORMER DATA RATINGS

Capacity
Self-cooled/
Maximum Nameplate
____________/______________kVA

Voltage Ratio (Generator Side/System side/Tertiary)
____________/_____________/______________kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
____________/_____________/______________

Fixed Taps Available _____________________________________________________

Present Tap Setting _____________________________________________________

Impedance: Positive \( Z_1 \) (on self-cooled kVA rating)______________ \% ________ X/R

Impedance: Zero \( Z_0 \) (on self-cooled kVA rating)______________ \% ________ X/R

EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request: ____________
Elevation: _____________  _____ Single Phase  _____ Three Phase

Inverter manufacturer, model name, number, and version:
_________________________________________________________________

List of adjustable setpoints for the protective equipment or software:
_________________________________________________________________

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

INDUCTION GENERATORS

(*) Field Volts: _________________
(*) Field Amperes: ______________
(*) Motoring Power (kW): __________
(*) Neutral Grounding Resistor (If Applicable): ____________
(*) I^2t or K (Heating Time Constant): ________________
(*) Rotor Resistance: ______________
(*) Stator Resistance: ______________
(*) Stator Reactance: ______________
(*) Rotor Reactance: ______________
(*) Magnetizing Reactance: __________
(*) Short Circuit Reactance: __________
(*) Exciting Current: ______________
(*) Temperature Rise: ______________
(*) Frame Size: _________________
(*) Design Letter: ________________
(*) Reactive Power Required In Vars (No Load): __________
(*) Reactive Power Required In Vars (Full Load): __________
(*) Total Rotating Inertia, H: __________ Per Unit on KVA Base

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required.
APPENDIX 4 TO GIP

INTERCONNECTION FACILITIES STUDY AGREEMENT

THIS AGREEMENT is made and entered into this ____ of _____________ 20___ by and between _________________ a __________________ and existing under the laws of the State of __________________ ("Interconnection Customer") and Southwest Power Pool, Inc. a non-profit organization under the laws of the State of Arkansas ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ____________, and

WHEREAS, Interconnection Customer desires to interconnect the Generating Facility with the Transmission System;

WHEREAS, Transmission Provider has completed a Definitive Interconnection System Impact Study (the "System Impact Study") and provided the results of said study to Interconnection Customer; and

WHEREAS, Interconnection Customer has requested Transmission Provider to perform an Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Definitive Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Generating Facility to the Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved GIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause an Interconnection Facilities Study consistent with Section 8.0 of this GIP to be performed in accordance with the Tariff.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.

4.0 The Interconnection Facilities Study report (i) shall provide a description, estimated cost of (consistent with Attachment A), schedule for required facilities to interconnect the Generating Facility to the Transmission System and (ii)
shall address the short circuit, instability, and power flow issues identified in the Definitive Interconnection System Impact Study.

5.0 Interconnection Customer shall meet the milestone requirements specified under Section 8.79 of the GIP prior to the performance of the Interconnection Facilities Study. The time for completion of the Interconnection Facilities Study is specified in Attachment A.

Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice. Any difference between the applicable deposits specified under Section 8.2 of the GIP and Interconnection Customer’s share of study costs shall be paid by or refunded to Interconnection Customer, as appropriate per Section 13.8.9 of the GIP.

6.0 Reserved

7.0 Governing Law

7.1 Governance. The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the United States of America except to the extent that the laws of the state of Arkansas may apply.

7.2 Applicability. This Agreement is subject to all applicable federal and state Laws and Regulations.

7.3 Reservation of Rights. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

8.0 Notices.

8.1 General. Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider:

                      Southwest Power Pool, Inc.
                      201 Worthen Drive
Little Rock, AR
Attention: Manager, GI Studies

To Interconnection Customer:


Attention: ______________________

8.2 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

9.0 Force Majeure

9.1 Economic Hardship. Economic hardship is not considered a Force Majeure event.

9.2 Default. Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 10), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

10.0 Indemnity

10.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party’s action or inactions of its obligations under this Agreement on behalf of the
indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

10.1.1 **Indemnified Person.** If an indemnified person is entitled to indemnification under this Article 10 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 10.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

10.1.2 **Indemnifying Party.** If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 10, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

10.1.3 **Indemnity Procedures.** Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 10.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not
be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

10.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

11.0 Assignment

11.1 Assignment. This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party’s, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.
12.0 Severability

12.1 Severability. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

13.0 Comparability

13.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

14.0 Deposits and Invoice Procedures

14.1 General. The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

14.2 Study Deposits. The Interconnection Customer shall provide study deposits, in accordance with the GIP to the Transmission Provider. The study deposits amounts and schedule shall be in accordance with the GIP.

14.3 Final Invoice. Within six months after completion of the studies Transmission Provider shall provide an invoice of the final cost of the studies and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

14.4 Payment. Invoices shall be rendered to the paying Party at the address specified in the Interconnection Request in Appendix 1 to the GIP. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under the GIP.
14.5 Disputes. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

15.0 Representations, Warranties, and Covenants

15.1 General. Each Party makes the following representations, warranties and covenants:

15.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

15.1.2 Authority. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

15.1.3 No Conflict. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.
15.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

16.0 Breach, Cure and Default

16.1 General. A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe any material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with the provisions of Section 17.4.

16.2 Events of Breach. A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

16.3 Cure and Default. Upon the occurrence of an event of Breach, the Party not in Breach (hereinafter the “Non-Breaching Party”), when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party (the “Breaching Party”) and to any other person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days to cure such Breach. If
the Breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement.

16.4 Right to Compel Performance. Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

17. Miscellaneous

17.1 Binding Effect. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

17.2 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

17.3 Rules of Interpretation. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder.

17.4 Entire Agreement. This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of
the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

17.5 **No Third Party Beneficiaries.** This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

17.6 **Waiver.** The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.7 **Headings.** The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

17.8 **Multiple Counterparts.** This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

17.9 **Amendment.** The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

17.10 **Modification by the Parties.** The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

17.11 **No Partnership.** This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

Miscellaneous. The Interconnection Facility Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver,
enforceability and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the GIP and the GIA.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: _________________________  By: ______________________________
Title: _________________________  Title: ______________________________
Date: __________________________  Date: ______________________________

[Insert name of Interconnection Customer]

By: _________________________
Title: _________________________
Date: _________________________
INTERCONNECTION CUSTOMER SCHEDULE ELECTION FOR CONDUCTING
THE INTERCONNECTION FACILITIES STUDY

Transmission Provider shall use Reasonable Efforts to complete the study and issue a
draft Interconnection Facilities Study report to Interconnection Customer within the following
number of days after receipt of an executed copy of this Interconnection Facilities Study
Agreement:

- ninety (90) Calendar Days with no more than a +/- 20 percent cost estimate
  contained in the report.
DATA FORM TO BE PROVIDED BY INTERCONNECTION CUSTOMER WITH THE INTERCONNECTION FACILITIES STUDY AGREEMENT

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections:

On the one line diagram indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line diagram indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

Will an alternate source of auxiliary power be available during CT/PT maintenance?

_____ Yes _____ No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? _____Yes _____ No (Please indicate on one line diagram).

What type of control system or PLC will be located at Interconnection Customer's Generating Facility?

_______________________________________________________________________

What protocol does the control system or PLC use?

_______________________________________________________________________

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

Physical dimensions of the proposed interconnection station:

_______________________________________________________________________

Bus length from generation to interconnection station:

_______________________________________________________________________

Line length from interconnection station to Transmission Provider's transmission line.

_______________________________________________________________________
Tower number observed in the field. (Painted on tower leg)*: ______________________
Number of third party easements required for transmission lines*: 
_______________________________________________________________________

* To be completed in coordination with Transmission Provider.

Is the Generating Facility in the Transmission Provider's service area? 
_____ Yes _____ No  Local provider: ______________________________________

Please provide proposed schedule dates:

<table>
<thead>
<tr>
<th>Event</th>
<th>Date:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Begin Construction</td>
<td>____________________</td>
</tr>
<tr>
<td>Generator step-up transformer</td>
<td>Date: ____________________</td>
</tr>
<tr>
<td>receives back feed power</td>
<td></td>
</tr>
<tr>
<td>Generation Testing</td>
<td>Date: ____________________</td>
</tr>
<tr>
<td>Commercial Operation</td>
<td>Date: ____________________</td>
</tr>
</tbody>
</table>

|
APPENDIX 4A TO GIP

LIMITED OPERATION INTERCONNECTION FACILITIES STUDY AGREEMENT

THIS AGREEMENT is made and entered into this ______ of _____________ 20___ by and between _________________ a ______________ and existing under the laws of the State of __________________ (“Interconnection Customer”) and Southwest Power Pool, Inc. a non-profit organization under the laws of the State of Arkansas (“Transmission Provider”). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ____________, and

WHEREAS, Interconnection Customer desires to interconnect the Generating Facility with the Transmission System;

WHEREAS, Transmission Provider has completed a Definitive Interconnection System Impact Study (the "System Impact Study") that requires Limited Operation in accordance with Section 8.4.3 as being necessary for the Interconnection Request and has provided the results of said study to Interconnection Customer; and

WHEREAS, Interconnection Customer has requested Transmission Provider to perform an Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Definitive Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Generating Facility to the Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved GIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause an Interconnection Facilities Study consistent with Section 8.0 of this GIP to be performed in accordance with the Tariff.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.
4.0 The Interconnection Facilities Study report (i) shall provide a description, estimated cost of (consistent with Attachment A), schedule for required facilities to interconnect the Generating Facility to the Transmission System and (ii) shall address the short circuit, instability, and power flow issues identified in the Definitive Interconnection System Impact Study.

5.0 Interconnection Customer shall meet the milestone requirements specified under Section 8.9 of the GIP prior to the performance of the Interconnection Facilities Study. The time for completion of the Interconnection Facilities Study is specified in Attachment A.

Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice. Any difference between the applicable deposits specified under Section 8.2 of the GIP and Interconnection Customer’s share of study costs shall be paid by or refunded to Interconnection Customer, as appropriate per Section 8.9 of the GIP.

6.0 Conditions for Limited Operation. Interconnection Customer agrees to the following conditions:

1. The Generating Facility will be allowed to operate under Limited Operation in accordance with Section 8.4.3 of the GIP before a Network Upgrades previously approved for construction under Section VI of Attachment O of this Tariff (“Previously Approved Network Upgrade”) is placed into service;

2. The Interconnection Customer will meet all requirements of the GIP;

3. The Interconnection Customer will provide financial security and authorize engineering, procurement, and construction of its cost assigned Network Upgrades and interconnection facilities no later than thirty (30) days after the effective date of the GIA; and

4. If the Transmission Provider determines that an earlier in-service date for a Previously Approved Network Upgrade can reasonably be met, then:
   a. If the Limited Operation Interconnection Facilities Study Agreement amount identified in Section 8.4.3 of the GIP is less than seventy-five (75) percent of the requested Interconnection Service, then the Interconnection Customer shall pay the cost of placing a Previously Approved Network Upgrade into service at an earlier date; or
   b. If the Limited Operation Interconnection Facilities Study Agreement amount identified in Section 8.4.3 of the GIP is greater than or equal to seventy-five (75) percent of the requested Interconnection Service, then the Interconnection
Customer may either accept Limited Operation until the scheduled in-service date of a Previously Approved Network Upgrade or pay the cost of placing a Previously Approved Network Upgrade into service at an earlier date.

7.0 Governing Law

7.1 Governance. The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the United States of America except to the extent that the laws of the state of Arkansas may apply.

7.2 Applicability. This Agreement is subject to all applicable federal and state Laws and Regulations.

7.3 Reservation of Rights. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

8.0 Notices.

8.1 General. Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider:

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR
Attention: Manager, GI Studies

To Interconnection Customer:

__________________________
__________________________
__________________________
Attention: ______________________
8.2 **Alternative Forms of Notice.** Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

9.0 **Force Majeure**

9.1 **Economic Hardship.** Economic hardship is not considered a Force Majeure event.

9.2 **Default.** Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 10), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

10.0 **Indemnity**

10.1 **Indemnity.** The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Partys’ action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

10.1.1 **Indemnified Person.** If an indemnified person is entitled to indemnification under this Article 10 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 10.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.
10.1.2 **Indemnifying Party.** If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 10, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

10.1.3 **Indemnity Procedures.** Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 10.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.
10.2 **Consequential Damages.** Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

11.0 **Assignment**

11.1 **Assignment.** This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party’s, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

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12.1 **Severability.** If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

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14.1 **General.** The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

14.2 **Study Deposits.** The Interconnection Customer shall provide study deposits, in accordance with the GIP to the Transmission Provider. The study deposits amounts and schedule shall be in accordance with the GIP.

14.3 **Final Invoice.** Within six months after completion of the studies Transmission Provider shall provide an invoice of the final cost of the studies and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

14.4 **Payment.** Invoices shall be rendered to the paying Party at the address specified in the Interconnection Request in Appendix 1 to the GIP. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under the GIP.

14.5 **Disputes.** In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC’s regulations at 18 CFR § 35.19a(a)(2)(iii).
15.0 Representations, Warranties, and Covenants

15.1 General. Each Party makes the following representations, warranties and covenants:

15.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

15.1.2 Authority. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

15.1.3 No Conflict. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

15.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

16.0 Breach, Cure and Default

16.1 General. A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe any material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in
Breach of this Agreement to cure such Breach in accordance with the provisions of Section 17.4.

16.2 Events of Breach. A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

16.3 Cure and Default. Upon the occurrence of an event of Breach, the Party not in Breach (hereinafter the “Non-Breaching Party”), when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party (the “Breaching Party”) and to any other person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days to cure such Breach. If the Breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement.

16.4 Right to Compel Performance. Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with
the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

17. Miscellaneous

17.1 Binding Effect. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

17.2 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

17.3 Rules of Interpretation. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder.

17.4 Entire Agreement. This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

17.5 No Third Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

17.6 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.
Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.7 **Headings.** The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

17.8 **Multiple Counterparts.** This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

17.9 **Amendment.** The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

17.10 **Modification by the Parties.** The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

17.11 **No Partnership.** This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

**IN WITNESS WHEREOF,** the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ___________________________ By: ___________________________

Title: __________________________ Title: __________________________

Date: __________________________ Date: __________________________
[Insert name of Interconnection Customer]

By: __________________________________

Title: __________________________________

Date: ________________________________
INTERCONNECTION CUSTOMER SCHEDULE ELECTION FOR CONDUCTING
THE LIMITED OPERATION INTERCONNECTION FACILITIES STUDY

Transmission Provider shall use Reasonable Efforts to complete the study and issue a
draft Interconnection Facilities Study report to Interconnection Customer within the following
number of days after receipt of an executed copy of this Interconnection Facilities Study
Agreement:

- ninety (90) Calendar Days with no more than a +/- 20 percent cost estimate
  contained in the report.
DATA FORM TO BE PROVIDED BY INTERCONNECTION CUSTOMER WITH THE
LIMITED OPERATION INTERCONNECTION FACILITIES STUDY AGREEMENT

Provide location plan and simplified one-line diagram of the plant and station facilities. For
staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the new ring bus or existing
Transmission Provider station. Number of generation connections:

On the one line diagram indicate the generation capacity attached at each metering location.
(Maximum load on CT/PT)

On the one line diagram indicate the location of auxiliary power. (Minimum load on CT/PT)
Amps

Will an alternate source of auxiliary power be available during CT/PT maintenance?

______ Yes ______ No

Will a transfer bus on the generation side of the metering require that each meter set be designed
for the total plant generation? ______ Yes ______ No (Please indicate on one line
diagram).

What type of control system or PLC will be located at Interconnection Customer's Generating
Facility?

_______________________________________________________________________

What protocol does the control system or PLC use?

_______________________________________________________________________

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line,
and property line.

Physical dimensions of the proposed interconnection station:

_______________________________________________________________________

Bus length from generation to interconnection station:

_______________________________________________________________________

Line length from interconnection station to Transmission Provider's transmission line.
Tower number observed in the field. (Painted on tower leg)*

Number of third party easements required for transmission lines*:

__________________________________________________________

* To be completed in coordination with Transmission Provider.

Is the Generating Facility in the Transmission Provider's service area?

_____ Yes _____ No Local provider: ___________________________________

Please provide proposed schedule dates:

Begin Construction Date: ________________________________

Generator step-up transformer Date: ________________________

receives back feed power

Generation Testing Date: _________________________________

Commercial Operation Date: ______________________________
APPENDIX 5 TO GIP

INTERIM AVAILABILITY INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____ day of ___________ 20___ by and between ___________________ a ________________ and existing under the laws of the State of ___________________ ("Interconnection Customer") and Southwest Power Pool, Inc. a non-profit organization under the laws of the State of Arkansas ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated _______________; and

WHEREAS, Interconnection Customer has a fully executed Definitive Interconnection System Impact Study Agreement and has submitted all requirements and milestones to be included in the Definitive Interconnection System Impact Study Queue;

WHEREAS, Interconnection Customer desires to interconnect the Generating Facility with the Transmission System on an interim basis before all such required studies under the GIP can be completed;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved GIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed an Interim Availability Interconnection System Impact Study as described in *Section 11A.2.4.1 of this GIP.

3.0 The scope of the Interim Availability Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interim Availability Interconnection System Impact Study will be based upon the technical information provided by Interconnection Customer in the Interconnection Request. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interim Availability Interconnection System Impact Study.
5.0 The Interim Availability Interconnection System Impact Study report shall provide the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
- identification of any thermal overload or voltage limit violations resulting from the interconnection;
- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection and
- description and non-binding, good faith estimated cost of facilities required to interconnect the Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues.

6.0 Interconnection Customer shall provide the deposit specified under Section 8.2 of the GIP for the performance of the Interim Availability Interconnection System Impact Study. Transmission Provider's good faith estimate for the time of completion of the Interim Availability Interconnection System Impact Study is [insert date].

Upon receipt of the Interim Availability Interconnection System Impact Study results, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interim Availability Interconnection System Impact Study.

Any difference between the deposit and Interconnection Customer’s study cost obligation shall be paid by or refunded to Interconnection Customer, as appropriate per Section 13.38.4 of the Generator Interconnection Procedures.

7.0 **Governing Law**

7.1 **Governance.** The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the United States of America except to the extent that the laws of the state of Arkansas may apply.

7.2 **Applicability.** This Agreement is subject to all applicable federal and state Laws and Regulations.

7.3 **Reservation of Rights.** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

8.0 **Notices.**
8.1 **General.** Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider:

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR
Attention: Manager, GI Studies

To Interconnection Customer:

__________________________
__________________________
__________________________
Attention: ______________________

8.2 **Alternative Forms of Notice.** Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

9.0 **Force Majeure**

9.1 **Economic Hardship.** Economic hardship is not considered a Force Majeure event.

9.2 **Default.** Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 10), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but
shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

10.0 Indemnity

10.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

10.1.1 Indemnified Person. If an indemnified person is entitled to indemnification under this Article 10 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 10.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

10.1.2 Indemnifying Party. If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 10, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

10.1.3 Indemnity Procedures. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 10.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the
indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

10.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

11.0 Assignment

11.1 Assignment. This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating
Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party’s, trustee’s or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

12.0 Severability

12.1 Severability. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

13.0 Comparability

13.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

14.0 Deposits and Invoice Procedures

14.1 General. The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

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estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

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14.5 Disputes. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

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15.1.2 Authority. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by
general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

15.1.3 No Conflict. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

15.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

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(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or
data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

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16.4 Right to Compel Performance. Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

17. Miscellaneous

17.1 Binding Effect. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

17.2 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

17.3 Rules of Interpretation. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and,
if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder.

17.4 Entire Agreement. This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

17.5 No Third Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

17.6 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.7 Headings. The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

17.8 Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

17.9 Amendment. The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

17.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the
Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

17.11 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

Miscellaneous. The Interim Availability Interconnection System Impact Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, that are consistent with regional practices, Applicable Laws and Regulations and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the GIP and the GIA.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: _________________________  By: ______________________________
Title: _________________________ Title: ______________________________
Date: __________________________ Date: ______________________________

[Insert name of Interconnection Customer]

By: _________________________
Title: _________________________
Date: _________________________
ASSUMPTIONS USED IN CONDUCTING THE INTERIM AVAILABILITY INTERCONNECTION SYSTEM IMPACT STUDY

The Interim Availability Interconnection System Impact Study will be based upon the information set forth in the Interconnection Requests and results of applicable prior studies, subject to any modifications in accordance with Section 4.4 of the GIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied.

[Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer, Transmission Owner and Transmission Provider]

GENERATING FACILITY DATA FOR THE INTERIM AVAILABILITY INTERCONNECTION SYSTEM IMPACT STUDY

UNIT RATINGS

Nameplate kVA ______________ °F _________ Voltage ____________
Prime Mover type _________________________
Power Factor: Lead _________ Lag _________ Connection (e.g. Wye) _____________
Speed (RPM) ___________ Frequency, Hertz ________________
Short Circuit Ratio ___________ Field Volts ________________
Stator Amperes at Rated kVA ___________ °F _________
Max Turbine Power: Summer MW _______ °F _________
                    Winter  MW ___________ °F _________

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = _________________ kW sec/kVA
Moment-of-Inertia, WR^2 = _________________ lb. ft.^2

REACTANCE DATA (PER UNIT-RATED KVA)

DIRECT AXIS QUADRATURE AXIS

Synchronous – saturated  X_{dv} _______ X_{qv} _______
Synchronous – unsaturated  \( X_{di} \)  \( X_{qi} \) 
Transient – saturated  \( X'_{dv} \)  \( X'_{qv} \) 
Transient – unsaturated  \( X'_{di} \)  \( X'_{qi} \) 
Subtransient – saturated  \( X''_{dv} \)  \( X''_{qv} \) 
Subtransient – unsaturated  \( X''_{di} \)  \( X''_{qi} \) 
Negative Sequence – saturated  \( X_{2v} \) 
Negative Sequence – unsaturated  \( X_{2i} \) 
Zero Sequence – saturated  \( X_{0v} \) 
Zero Sequence – unsaturated  \( X_{0i} \) 
Leakage Reactance  \( X_{lm} \)

FIELD TIME CONSTANT DATA (SEC)

Open Circuit  \( T'_{do} \)  \( T'_{qo} \) 
Three-Phase Short Circuit Transient  \( T'_{d3} \)  \( T'_{q} \) 
Line to Line Short Circuit Transient  \( T'_{d2} \) 
Line to Neutral Short Circuit Transient  \( T'_{d1} \) 
Short Circuit Subtransient  \( T''_{d} \)  \( T''_{q} \) 
Open Circuit Subtransient  \( T''_{do} \)  \( T''_{qo} \)

ARMATURE TIME CONSTANT DATA (SEC)

Three Phase Short Circuit  \( T_{a3} \) 
Line to Line Short Circuit  \( T_{a2} \) 
Line to Neutral Short Circuit  \( T_{a1} \)

NOTE: If requested information is not applicable, indicate by marking "N/A."

MW CAPABILITY AND PLANT CONFIGURATION
GENERATING FACILITY DATA

ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive  \( R_{1} \) 
Negative  \( R_{2} \) 
Zero  \( R_{0} \)

Rotor Short Time Thermal Capacity \( I_{2}^{2}t = \) 
Field Current at Rated kVA, Armature Voltage and PF = \( \) amps
Field Current at Rated kVA and Armature Voltage, 0 PF = \( \) amps
Three Phase Armature Winding Capacitance = ______ microfarad
Field Winding Resistance = ______ ohms _____ °C
Armature Winding Resistance (Per Phase) = ______ ohms _____ °C

CURVES
Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

GENERATOR STEP-UP TRANSFORMER DATA RATINGS
Capacity Self-cooled/
Maximum Nameplate
/ kVA
Voltage Ratio (Generator Side/System side/Tertiary)
/ / kV
Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
/ / /
Fixed Taps Available _____________________________________________________
Present Tap Setting _______________________________________________________
Impedance: Positive \( Z_1 \) (on self-cooled kVA rating) % X/R
Impedance: Zero \( Z_0 \) (on self-cooled kVA rating) % X/R

EXCITATION SYSTEM DATA
Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

GOVERNOR SYSTEM DATA
Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.
WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request:

Elevation: __________ Single Phase ____ Three Phase

Inverter manufacturer, model name, number, and version:

List of adjustable setpoints for the protective equipment or software:

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

INDUCTION GENERATORS

(*) Field Volts: ______________
(*) Field Amperes: __________
(*) Motoring Power (kW): __________
(*) Neutral Grounding Resistor (If Applicable): __________
(*) I^2t or K (Heating Time Constant): __________
(*) Rotor Resistance: __________
(*) Stator Resistance: __________
(*) Stator Reactance: __________
(*) Rotor Reactance: __________
(*) Magnetizing Reactance: __________
(*) Short Circuit Reactance: __________
(*) Exciting Current: __________
(*) Temperature Rise: __________
(*) Frame Size: __________
(*) Design Letter: __________
(*) Reactive Power Required In Vars (No Load): __________
(*) Reactive Power Required In Vars (Full Load): __________
(*) Total Rotating Inertia, H: __________ Per Unit on KVA Base

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required.
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GENERATOR INTERCONNECTION AGREEMENT

THIS GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this ____ day of ___________ 20__, by and among
__________________________________________, a ____________________________ organized and existing under the laws of the State/Commonwealth of ________________ ("Interconnection Customer" with a Generating Facility), Southwest Power Pool, Inc., a corporation organized and existing under the laws of the State of Arkansas ("Transmission Provider") and
__________________________________________, a ___________________________ organized and existing under the laws of the State/Commonwealth of ________________ ("Transmission Owner"). Interconnection Customer, Transmission Provider and Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

Recitals

WHEREAS, Transmission Provider functionally controls the operation of the Transmission System; and,

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Transmission Owner owns facilities to which the Generating Facility is to be interconnected and may be constructing facilities to allow the interconnection; and,

WHEREAS, Interconnection Customer, Transmission Provider and Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Generating Facility with the Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).
Article 1. Definitions

**Adverse System Impact** shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

**Affected System** shall mean an electric system other than the Transmission System that may be affected by the proposed interconnection.

**Affected System Operator** shall mean the entity that operates an Affected System.

**Affiliate** shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

**Ancillary Services** shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

**Applicable Laws and Regulations** shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

**Applicable Reliability Council** shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

**Applicable Reliability Standards** shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

**Base Case** shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider.

**Breach** shall mean the failure of a Party to perform or observe any material term or condition of the Generator Interconnection Agreement.

**Breaching Party** shall mean a Party that is in Breach of the Generator Interconnection Agreement.

**Business Day** shall mean Monday through Friday, excluding Federal Holidays.

**Calendar Day** shall mean any day including Saturday, Sunday or a Federal Holiday.

**Clustering** shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting Interconnection Studies.
Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Generator Interconnection Agreement.

Definitive Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in a Preliminary Interconnection System Impact Study or that may be caused by the withdrawal or addition of an Interconnection Request, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Generator Interconnection Procedures.

Definitive Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3A of the Generator Interconnection Procedures for conducting the Definitive Interconnection System Impact Study.

Definitive Interconnection System Impact Study Queue shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for a Definitive Interconnection System Impact Study.

Dispute Resolution shall mean the procedure in Section 12 of the Tariff for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Owner’s facilities and equipment that are not included in the Transmission System. The voltage levels at which Distribution Systems operate differ among areas.
**Distribution Upgrades** shall mean the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

**Effective Date** shall mean the date on which the Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

**Emergency Condition** shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System or the electric systems of others to which the Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Owner’s Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Generator Interconnection Agreement to possess black start capability.

**Energy Resource Interconnection Service** shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

**Engineering & Procurement (E&P) Agreement** shall mean an agreement that authorizes the Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

**Environmental Law** shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.


**FERC** shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

**Force Majeure** shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure
event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

**Generating Facility** shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

**Generating Facility Capacity** shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

**Generator Interconnection Agreement (GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility that is included in the Transmission Provider's Tariff.

**Generator Interconnection Procedures (GIP)** shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility that are included in the Transmission Provider's Tariff.

**Good Utility Practice** shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

**Governmental Authority** shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, Transmission Owner or any Affiliate thereof.

**Hazardous Substances** shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

**Initial Synchronization Date** shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.
**In-Service Date** shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Owner's Interconnection Facilities to obtain back feed power.

**Interconnection Customer** shall mean any entity, including the Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission System.

**Interconnection Customer's Interconnection Facilities** shall mean all facilities and equipment, as identified in Appendix A of the Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

**Interconnection Facilities** shall mean the Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

**Interconnection Facilities Study** shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Definitive Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission System. The scope of the study is defined in Section 8 of the Generator Interconnection Procedures.

**Interconnection Facilities Study Agreement** shall mean the form of agreement contained in Appendix 4 of the Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

**Interconnection Facilities Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for an Interconnection Facilities Study.

**Interconnection Feasibility Study** shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission System, the scope of which is described in Section 6 of the Generator Interconnection Procedures.

**Interconnection Feasibility Study Agreement** shall mean the form of agreement contained in Appendix 2 of the Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

**Interconnection Feasibility Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for an Interconnection Feasibility Study.
Interconnection Queue Position shall mean the order of a valid Interconnection Request within the Interconnection Facilities Study Queue, relative to all other pending valid Interconnection Requests within the Interconnection Facilities Study Queue, which is established based upon the requirements in Section 4.1.3 of the Generator Interconnection Procedures.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Generator Interconnection Agreement and, if applicable, the Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Preliminary Interconnection System Impact Study, the Definitive Interconnection System Impact Study and the Interconnection Facilities Study described in the Generator Interconnection Procedures.

Interconnection Study Agreement shall mean any of the following agreements: the Interconnection Feasibility Study Agreement, the Preliminary Interconnection System Impact Study Agreement, the Definitive Interconnection System Impact Study Agreement and the Interconnection Facilities Study Agreement described in the Generator Interconnection Procedures.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customer, Transmission Owner and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.
NERC shall mean the North American Electric Reliability Corporation or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission System in a manner comparable to that in which the Transmission Owner integrates its generating facilities to serve Native Load Customers as a Network Resource. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission System to accommodate the interconnection of the Generating Facility to the Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Generator Interconnection Agreement or its performance.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Owner's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission System.

Preliminary Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in an Interconnection Feasibility Study or that may be caused by an Interconnection Request, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Generator Interconnection Procedures.

Preliminary Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Generator Interconnection Procedures for conducting the Preliminary Interconnection System Impact Study.
**Preliminary Interconnection System Impact Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for a Preliminary Interconnection System Impact Study.

**Previous Network Upgrade** shall mean a Network Upgrade that is needed for the interconnection of one or more Interconnection Customers’ Generating Facilities, but is not the cost responsibility of the Interconnection Customer, subject to restudy, and which is identified in Appendix A of the Generator Interconnection Agreement.

**Queue** shall mean the Interconnection Feasibility Study Queue, the Preliminary Interconnection System Impact Study Queue, or the Definitive Interconnection System Impact Study Queue, or the Interconnection Facilities Study Queue, as applicable.

**Queue Position** shall mean the order of a valid Interconnection Request within the Interconnection Feasibility Study Queue, relative to all other pending valid Interconnection Requests within the Interconnection Feasibility Study Queue, the order of a valid Interconnection Request within the Preliminary Interconnection System Impact Study Queue, relative to all other pending valid Interconnection Requests within the Preliminary Interconnection System Impact Study Queue, or the order of a valid Interconnection Request within the Definitive Interconnection System Impact Study Queue, relative to all other pending valid Interconnection Requests within the Definitive Interconnection System Impact Study Queue, as applicable, that is established based upon the date and time of receipt of the valid Interconnection Request and the date and time of receipt of other information specified under Section 4.1 of this GIP, as applicable, by the Transmission Provider.

**Reasonable Efforts** shall mean, with respect to an action required to be attempted or taken by a Party under the Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

**Scoping Meeting** shall mean the meeting between representatives of the Interconnection Customer, Transmission Owner and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

**Shared Network Upgrade** shall mean a Network Upgrade listed in Appendix A of the Generator Interconnection Agreement that is needed for the interconnection of multiple Interconnection Customers’ Generating Facilities and which is the shared funding responsibility of such Interconnection Customers that may also benefit other Interconnection Customer(s) that are later identified as beneficiaries.

**Site Control** shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site of sufficient size for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site of sufficient size for such purpose.
**Small Generating Facility** shall mean a Generating Facility that has an aggregate net Generating Facility Capacity of no more than 2 MW.

**Stand Alone Network Upgrades** shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. The Transmission Provider, Transmission Owner and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Generator Interconnection Agreement.

**System Protection Facilities** shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission System or on other delivery systems or other generating systems to which the Transmission System is directly connected.

**Tariff** shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

**Transmission Owner** shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Generator Interconnection Agreement to the extent necessary.

**Transmission Provider** shall mean the public utility (or its Designated Agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

**Transmission Owner's Interconnection Facilities** shall mean all facilities and equipment owned, controlled or operated by the Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades Stand Alone Network Upgrades or Network Upgrades.

**Transmission System** shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

**Trial Operation** shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

**Variable Energy Resource** shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility
owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Article 2. Effective Date, Term, and Termination

2.1 Effective Date. This GIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this GIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 Term of Agreement. Subject to the provisions of Article 2.3, this GIA shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as Interconnection Customer may request (Term to be specified in individual agreements) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This GIA may be terminated by Interconnection Customer after giving Transmission Provider and Transmission Owner ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 If the Generating Facility fails to achieve Commercial Operation for three (3) consecutive years following the Commercial Operation Date, this GIA may be terminated by the Transmission Provider after giving the Interconnection Customer ninety (90) Calendar Days advance written notice. Where a portion of the Generating Facility fails to achieve Commercial Operation for three (3) consecutive years following the Commercial Operation Date, the Transmission Provider shall issue a revised GIA to reflect the amount of the Generating Facility Capacity that achieved Commercial Operation.

2.3.3 Default. Any Party may terminate this GIA in accordance with Article 17.

2.3.4 Notwithstanding Articles 2.3.1, 2.3.2 and 2.3.3, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this GIA, which notice has been accepted for filing by FERC.

2.4 Termination Costs. If a Party elects to terminate this Agreement pursuant to Article 2.3 above, Interconnection Customer and Transmission Owner shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by any other Party, as of the date of such Party's receipt of such notice of termination, that are the responsibility of the Terminating Party under this GIA. In the event of termination by any Party, all Parties shall use Commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this GIA, unless otherwise ordered or approved by FERC:
2.4.1 With respect to any portion of Transmission Owner's Interconnection Facilities that have not yet been constructed or installed, Transmission Owner shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Owner shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Owner for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Owner shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this GIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which Transmission Owner has incurred expenses and has not been reimbursed by Interconnection Customer and the Interconnection Customer’s allocated share of Network Upgrade(s) costs as calculated pursuant to Section 4.2.5 of the GIP and as listed in Appendix A of this GIA which are required for service to other Interconnection Customer(s).

2.4.2 Transmission Owner may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Owner shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this GIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 Disconnection. Upon termination of this GIA, the Parties will take all appropriate steps to disconnect the Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this GIA or such non-terminating Party otherwise is responsible for these costs under this GIA.

2.6 Survival. This GIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this GIA; to permit payments for any credits under this GIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this GIA was in effect; and to
permit each Party to have access to the lands of another Party pursuant to this GIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

Article 3. Regulatory Filings

3.1 Filing. Transmission Provider shall file this GIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this GIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

Article 4. Scope of Service

4.1 Interconnection Product Options. Interconnection Customer has selected the following (checked) type of Interconnection Service:

4.1.1 Energy Resource Interconnection Service.

4.1.1.1 The Product. Energy Resource Interconnection Service allows Interconnection Customer to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Appendix A.

4.1.1.2 Transmission Delivery Service Implications. Under Energy Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Generating Facility into and deliver power across the Transmission System on an "as available" basis. The Interconnection Customer's ability to inject its Generating Facility's output beyond the Point of Interconnection, therefore, will depend on the existing capacity of the Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of Firm Point-To-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

4.1.2 Network Resource Interconnection Service.

4.1.2.1 The Product. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Generating Facility in a manner comparable to that in which Transmission Owner integrates its generating facilities to serve Native Load Customers as all Network Resources. To the extent Interconnection Customer wants to
receive Network Resource Interconnection Service, Transmission Owner shall construct the facilities identified in Appendix A to this GIA.

4.1.2.2 Transmission Delivery Service Implications. Network Resource Interconnection Service allows Interconnection Customer's Generating Facility to be designated by any Network Customer under the Tariff on the Transmission System as a Network Resource, up to the Generating Facility's full output, on the same basis as existing Network Resources interconnected to the Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Generating Facility in the same manner as it accesses Network Resources. A Generating Facility receiving Network Resource Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or Firm Point-To-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Generating Facility to any particular load on the Transmission System without incurring congestion costs. In the event of transmission constraints on the Transmission System, Interconnection Customer's Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that Interconnection Customer’s Generating Facility be designated as a Network Resource by a Network Service Customer under the Tariff or that Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does
designate the Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission service request for delivery from the Generating Facility within the Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Generating Facility be undertaken, regardless of whether or not such Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Generating Facility outside the Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

4.2 **Provision of Service.** Transmission Provider shall provide Interconnection Service for the Generating Facility at the Point of Interconnection.

4.3 **Performance Standards.** Each Party shall perform all of its obligations under this GIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this GIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the GIA and submit the amendment to FERC for approval.

4.4 **No Transmission Delivery Service.** The execution of this GIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 **Interconnection Customer Provided Services.** The services provided by Interconnection Customer under this GIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.86.

5.1 **Options.** Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either the Option To Build as described under Article 5.1.2 or the Negotiated Option described under Article 5.1.3 if the Interconnection Customer and the
Transmission Owner cannot reach agreement under the Standard Option described under Article 5.1.1, for completion of Transmission Owner's Interconnection Facilities and Network Upgrades as set forth in Appendix A, Interconnection Facilities and Network Upgrades, and such dates and selected option, as applicable, shall be set forth in Appendix B, Milestones.

5.1.1 Standard Option. Transmission Owner shall design, procure, and construct Transmission Owner’s Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Owner’s Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Owner reasonably expects that it will not be able to complete Transmission Owner’s Interconnection Facilities and Network Upgrades by the specified dates, Transmission Owner shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 Option to Build. If the dates designated by Interconnection Customer are not acceptable to Transmission Owner, Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.1. Transmission Owner and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.3 Negotiated Option. If Interconnection Customer elects not to exercise its option under Article 5.1.2, Option to Build, Interconnection Customer shall so notify Transmission Provider and Transmission Owner within thirty (30) Calendar Days, and the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection Customer) pursuant to which Transmission Owner is responsible for the design, procurement and construction of Transmission Owner’s Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Transmission Owner shall assume responsibility for the design, procurement and construction of Transmission Owner’s Interconnection Facilities and Network Upgrades pursuant to 5.1.1, Standard Option.
5.2 **General Conditions Applicable to Option to Build.** If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Owner;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Owner shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(4) Prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider and Transmission Owner a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider and Transmission Owner;

(5) At any time during construction, Transmission Owner shall have the right to gain unrestricted access to Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) At any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Owner, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider and Transmission Owner for claims arising from Interconnection Customer's construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) The Interconnection Customer shall transfer control of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;
(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Owner's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Owner not later than the Commercial Operation Date;

(10) Transmission Owner shall approve and accept for operation and maintenance Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information, and any other documents that are reasonably required by Transmission Owner to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

5.3 Liquidated Damages. The actual damages to Interconnection Customer, in the event Transmission Owner’s Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Owner pursuant to subparagraph 5.1.3, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Owner to Interconnection Customer in the event that Transmission Owner does not complete any portion of Transmission Owner’s Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to $\frac{1}{2}$ of 1 percent per day of the actual cost of Transmission Owner’s Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Owner has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Owner’s Interconnection Facilities and Network Upgrades for which Transmission Owner has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Owner to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this GIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Owner’s failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Owner’s Interconnection Facilities or Network Upgrades to take the delivery of power for the Generating Facility's Trial Operation or to export power from the Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Owner’s Interconnection Facilities or Network Upgrades to take the delivery of power for Generating Facility's Trial Operation or to export power from the Generating Facility, but for Transmission Owner’s delay; (2) Transmission Owner’s failure to meet the specified dates is the result of the action or inaction of Interconnection
Customer or any other Interconnection Customer who has entered into a GIA with Transmission Owner or any cause beyond Transmission Owner’s reasonable control or reasonable ability to cure; (3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 **Power System Stabilizers.** The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Generating Facility. If the Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Owner’s system operator, or its designated representative. The requirements of this paragraph shall not apply to wind generators.

5.5 **Equipment Procurement.** If responsibility for construction of Transmission Owner’s Interconnection Facilities or Network Upgrades is to be borne by Transmission Owner, then Transmission Owner shall commence design of Transmission Owner’s Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Interconnection Facilities Study pursuant to the Interconnection Facilities Study Agreement;

5.5.2 Transmission Owner has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.5.3 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.75 by the dates specified in Appendix B, Milestones.

5.6 **Construction Commencement.** Transmission Owner shall commence construction of Transmission Owner’s Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Owner’s Interconnection Facilities and Network Upgrades;

5.6.3 Transmission Owner has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and
5.6.4 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.75 by the dates specified in Appendix B, Milestones.

5.7 Work Progress. The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Parties may, at any time, request a progress report from other Parties. If, at any time, Interconnection Customer determines that the completion of Transmission Owner’s Interconnection Facilities and Network Upgrades will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider and Transmission Owner of such later date upon which the completion of Transmission Owner’s Interconnection Facilities and Network Upgrades will be required.

5.8 Information Exchange. As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with the Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Limited Operation. If any of Transmission Owner’s Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Generating Facility and Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Owner’s Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this GIA ("Limited Operation"). In accordance with Article 11.6 of the GIA, the Interconnection Customer may also choose to proceed with Limited Operation consistent with the interconnection capacity that is available. Transmission Owner shall permit Interconnection Customer to operate the Generating Facility and Interconnection Customer's Interconnection Facilities under Limited Operation in accordance with the results of such studies performed by Transmission Provider.

5.10 Interconnection Customer's Interconnection Facilities ('ICIF'). Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.10.1 Interconnection Customer's Interconnection Facility Specifications. Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Owner at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Owner shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner and comment on such specifications within thirty (30) Calendar Days of
Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Transmission Owner’s Review. Transmission Owner’s review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Owner, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner.

5.10.3 ICIF Construction. The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Generating Facility. The Interconnection Customer shall provide Transmission Owner specifications for the excitation system, automatic voltage regulator, Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.10.4 Updated Information Submission by Interconnection Customer. The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date. Interconnection Customer shall submit a completed copy of the Generating Facility data requirements contained in Appendix 1 to the GIP. It shall also include any additional information provided to Transmission Provider for the Interconnection Feasibility and Interconnection Facilities Studies. Information in this submission shall be the most current Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study agreements between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on the Transmission System based on the actual data submitted pursuant to
this Article 5.10.4. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

5.10.5 Information Supplementation. Prior to the Commercial Operation Date, or as soon as possible thereafter, the Parties shall supplement their information submissions described above in this Article 5 with any and all “as-built” Generating Facility information or “as-tested” performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Generating Facility as required by Good Utility Practice such as an open circuit “step voltage” test on the Generating Facility to verify proper operation of the Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent (5 percent) change in Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Generating Facility’s terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Generating Facility terminal or field voltages is provided. Generating Facility testing shall be conducted and results provided to the Transmission Provider for each individual generating unit in a station.

Subsequent to the Commercial Operation Date, the Interconnection Customer shall provide Transmission Owner and Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Owner shall provide the Interconnection Customer and Transmission Provider any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Owner-owned substation that may affect the Interconnection Customer’s Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

5.11 Transmission Owner’s Interconnection Facilities Construction. Transmission Owner’s Interconnection Facilities and Network Upgrades shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Owner shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Owner’s Interconnection Facilities and Network Upgrades [include appropriate drawings and relay diagrams].
Transmission Owner will obtain control of Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

5.12 **Access Rights.** Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to any other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Generating Facility with the Transmission System; (ii) operate and maintain the Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this GIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 **Lands of Other Property Owners.** If any part of Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Owner, Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 **Permits.** Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 **Early Construction of Base Case Facilities.** Interconnection Customer may request Transmission Owner to construct, and Transmission Owner shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 **Suspension.**
5.16.1 Interconnection Customer, upon written notice to Transmission Provider and Transmission Owner, may suspend, for a period not to exceed 18 months, work by Transmission Owner associated with the construction and installation of Transmission Owner’s Interconnection Facilities and/or Network Upgrades required under this GIA under the following terms and conditions,

i. Construction of Network Upgrades that are required to provide Interconnection Service to other Generating Facilities and for which Interconnection Customer shares cost responsibility cannot be suspended pursuant to this Article 5.16.

ii. If the suspension period begins later than or extends beyond six months following the Effective Date of the GIA, the Interconnection Customer shall provide to the Transmission Provider security in the form described under Article 11.75 in an amount equal to the greater of:

a. the Interconnection Customer’s allocated share of Network Upgrade(s) as calculated pursuant to Section 4.2.5 of the GIP and as identified in Appendix A of this GIA unless previously provided under Section 8.79 of the GIP; or

b. $5,000,000 if the Generating Facility is greater than or equal to 100 MW; or
c. $2,500,000 if the Generating Facility is greater than or equal to 50 MW and less than 100 MW; or
d. $1,000,000 if the Generating Facility is less than 50 MW; or
e. $500,000 if the Generating Facility is less than or equal to 2 MW.

iii. In the event that this GIA is terminated under this Article 5.16, the Transmission Provider shall retain the security provided pursuant to Article 5.16.1.ii in the amount required to meet Interconnection Customer’s obligations pursuant to this GIA. Any difference between the security provided and Interconnection Customer’s obligations shall be settled pursuant to Article 12.

iv. In the event Interconnection Customer suspends work by Transmission Owner required under this GIA pursuant to this Article 5.16 and has not requested Transmission Owner to resume the work required under this GIA on or before the expiration of 18 months from the date of suspension, this GIA shall be deemed terminated unless Article 16 applies.

v. In the event Interconnection Customer suspends work by Transmission Owner required under this GIA pursuant to this Article 5.16 and has not complied requirements of Article 5.16.1.ii on or before the later of the expiration of 6 months following the effective date of the GIA or the date the suspension is requested, this GIA shall be deemed terminated by the Interconnection Customer.

vi. In the event Interconnection Customer suspends work by Transmission Owner required under this GIA pursuant to this Article 5.16, the Transmission System
shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Owner’s safety and reliability criteria. Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Owner and Transmission Provider (i) have incurred pursuant to this GIA prior to the suspension and (ii) incur in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Owner cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Owner shall obtain Interconnection Customer's authorization to do so. Transmission Owner and Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs.

vii. In the event Interconnection Customer provides written notice to resume work for those facilities for which work has been suspended pursuant to this Article 5.16.1, the Interconnection Customer shall receive a refund, including interest, of any payments provided in accordance with Article 5.16.1.ii in excess of the sum of Interconnection Customer's allocated share of Network Upgrade(s) costs and any costs incurred under Article 5.16.1.vi within 30 days of the date of such notice.

5.16.2 Exemptions. The Interconnection Customer shall be exempt from the payments described under Article 5.16.1.ii.b, 5.16.1.ii.c and 5.16.1.ii.d if the following occurs or Suspension is requested for the following reasons:

i. Construction of a Network Upgrade or the Generating Facility is prevented by order of a Governmental Authority; or

ii. Transmission Provider determines through an Interconnection Study that the Suspension does not qualify as a modification that has an impact on the cost or timing of any Interconnection Request with an equal or later Queue priority date (Material Modification); or

iii. Transmission Owner or Transmission Provider determines that a Force Majeure event prevents construction of a Network Upgrade.

5.17 Taxes.

5.17.1 Interconnection Customer Payments Not Taxable. The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Owner for the installation of Transmission Owner's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in
aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 **Representations and Covenants.** In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Owner for Transmission Owner's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of Transmission Owner's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Transmission Owner's request, Interconnection Customer shall provide Transmission Owner with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Owner represents and covenants that the cost of Transmission Owner's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 **Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Owner.** Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Transmission Owner from the cost consequences of any current tax liability imposed against Transmission Owner as the result of payments or property transfers made by Interconnection Customer to Transmission Owner under this GIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Owner. Transmission Owner shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this GIA unless (i) Transmission Owner has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Owner should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Owner to report payments or property as income subject to taxation; provided, however, that Transmission Owner may require Interconnection Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to Transmission Owner (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Owner for such costs on
a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Owner of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission Owner upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 Tax Gross-Up Amount. Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the Parties, this means that Interconnection Customer will pay Transmission Owner, in addition to the amount paid for the Interconnection Facilities, and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Owner ("Current Taxes") on the excess of (a) the gross income realized by Transmission Owner as a result of payments or property transfers made by Interconnection Customer to Transmission Owner under this GIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Owner to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Owner’s composite federal and state tax rates at the time the payments or property transfers are received and Transmission Owner will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Transmission Owner’s anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Owner’s current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 Private Letter Ruling or Change or Clarification of Law. At Interconnection Customer's request and expense, Transmission Owner shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission Owner under this GIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and
accurate to the best of Interconnection Customer's knowledge. Transmission Owner and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Owner shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Owner shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 Subsequent Taxable Events. If, within 10 years from the date on which the relevant Transmission Owner’s Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this GIA terminates and Transmission Owner retains ownership of the Interconnection Facilities and Network Upgrades, Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Owner, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 Contests. In the event any Governmental Authority determines that Transmission Owner’s receipt of payments or property constitutes income that is subject to taxation, Transmission Owner shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Owner may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Owner may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Owner reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Owner shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Owner on a periodic basis, as invoiced by Transmission Owner, Transmission Owner’s documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Owner may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Owner, but
reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Owner for the tax at issue in the contest.

5.17.8 Refund. In the event that (a) a private letter ruling is issued to Transmission Owner which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Owner under the terms of this GIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Owner in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Owner under the terms of this GIA is not taxable to Transmission Owner, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Owner are not subject to federal income tax, or (d) if Transmission Owner receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Owner pursuant to this GIA, Transmission Owner shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amount paid by Interconnection Customer to Transmission Owner for such taxes which Transmission Owner did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Owner refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Owner, any refund or credit Transmission Owner receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Owner for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Owner to any Governmental Authority resulting from an offset or credit); provided, however, that Transmission Owner will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Owner has received a tax refund, credit or offset from any Governmental Authority for any applicable
overpayment of income tax related to Transmission Owner’s Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 Taxes Other Than Income Taxes. Upon the timely request by Interconnection Customer, and at Interconnection Customer’s sole expense, Transmission Owner may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Owner for which Interconnection Customer may be required to reimburse Transmission Owner under the terms of this GIA. Interconnection Customer shall pay to Transmission Owner on a periodic basis, as invoiced by Transmission Owner, Transmission Owner’s documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Owner for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Owner.

5.18 Tax Status. All Parties shall cooperate with each other to maintain their tax status. Nothing in this GIA is intended to adversely affect any Party’s tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

5.19 Modification.

5.19.1 General. Each Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect another Party's facilities, that Party shall provide to the other Parties sufficient information regarding such modification so that the other Parties may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Parties at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission
Owner shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Owner’s Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this GIA and Good Utility Practice.

5.19.3 Modification Costs. Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Owner makes to Transmission Owner’s Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Owner’s Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

5.20 Delays. If a Network Upgrade(s) identified in Appendix A is delayed during the construction process and the Commercial Operation Date for the Generating Facility identified in Appendix B is no longer feasible, the Commercial Operation Date in Appendix B may be modified to no later than six (6) months following the in-service date for the last Network Upgrade identified in Appendix A.

Article 6. Testing and Inspection

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, Transmission Owner shall test Transmission Owner’s Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require
reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 **Right to Observe Testing.** Each Party shall notify the other Parties in advance of its performance of tests of its Interconnection Facilities. The other Parties have the right, at its own expense, to observe such testing.

6.4 **Right to Inspect.** Each Party shall have the right, but shall have no obligation to: (i) observe another Parties’ tests and/or inspection of any of its System Protection Facilities and other protective equipment, including power system stabilizers; (ii) review the settings of the other Parties’ System Protection Facilities and other protective equipment; and (iii) review another Parties’ maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. Any Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Parties. The exercise or non-exercise by another Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that any Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this GIA.

**Article 7. Metering**

7.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Owner shall install Metering Equipment at the Point of Interconnection prior to any operation of the Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Generating Facility shall be measured at or, at Transmission Owner’s option, compensated to, the Point of Interconnection. Transmission Owner shall provide metering quantities, in analog and/or digital form, to Interconnection Customer and Transmission Provider on a same-time basis using communication as provided in Article 8. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 **Check Meters.** Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Owner’s meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this GIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Owner or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 **Standards.** Transmission Owner shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.
7.4 **Testing of Metering Equipment.** Transmission Owner shall inspect and test all Transmission Owner-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Owner shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two (2) years. Transmission Owner shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Owner’s failure to maintain, then Transmission Owner shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Owner shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 **Metering Data.** At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Owner and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Generating Facility to the Point of Interconnection.

**Article 8. Communications**

8.1 **Interconnection Customer Obligations.** Interconnection Customer shall maintain satisfactory operating communications with Transmission Owner’s Transmission System dispatcher or representative designated by Transmission Owner. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Owner as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Generating Facility to the location(s) specified by Transmission Owner. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 **Remote Terminal Unit.** Prior to the Initial Synchronization Date of the Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Owner at Interconnection Customer's expense, to gather accumulated and
instantaneous data to be telemetered to the location(s) designated by Transmission Owner through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Owner. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Owner.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 **No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 **Provision of Data from a Variable Energy Resource.** The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider’s development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with (i) site-specific meteorological data including: temperature, wind speed, wind direction, relative humidity and atmospheric pressure and (ii) site specific geographic data including location (latitude and longitude) of the Variable Energy Resource and location (latitude and longitude) and height of the facility that will contain the equipment necessary to provide the meteorological data for such resource. The Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider’s development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological, geographical and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological, geographical and forced outage data are set forth in Appendix C, Interconnection Details, of this L-GIA, as they may change from time to time.
Article 9. Operations

9.1 General. Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Parties all information that may reasonably be required by the other Parties to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 Control Area Notification. At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider and Transmission Owner in writing of the Control Area in which the Generating Facility will be located. If Interconnection Customer elects to locate the Generating Facility in a Control Area other than the Control Area in which the Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this GIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Generating Facility in the other Control Area.

9.3 Transmission Provider and Transmission Owner Obligations. Transmission Provider and Transmission Owner shall cause the Transmission System and Transmission Owner’s Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this GIA. Transmission Provider or Transmission Owner may provide operating instructions to Interconnection Customer consistent with this GIA and Transmission Owner’s operating protocols and procedures as they may change from time to time. Transmission Provider and Transmission Owner will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA. Interconnection Customer shall operate the Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this GIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Any Party may request that another Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this GIA.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, the Interconnection Customer is responsible for the proper synchronization of the Generating Facility to the Transmission System.

9.6 Reactive Power.

9.6.1 Power Factor Design Criteria. Interconnection Customer shall design the Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of...
0.95 leading to 0.95 lagging, unless Transmission Provider or Transmission Owner has established different requirements that apply to all generators in the Control Area on a comparable basis. A wind generator plant shall maintain a power factor within the range of .95 leading to .95 lagging, measured at the Point of Interconnection as defined in the GIA, if the Transmission Provider’s System Impact Study shows that such a requirement is necessary to ensure safety or reliability.

9.6.2 Voltage Schedules. Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Transmission Provider and/or Transmission Owner shall require Interconnection Customer to operate the Generating Facility to produce or absorb reactive power within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Owner’s voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Owner shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the Transmission Owner.

9.6.2.1 Governors and Regulators. Whenever the Generating Facility is operated in parallel with the Transmission System and the speed governors (if installed on the generating unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, Interconnection Customer shall operate the Generating Facility with its speed governors and voltage regulators in automatic operation. If the Generating Facility's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify Transmission Owner’s system operator, or its designated representative, and ensure that such Generating Facility's reactive power production or absorption (measured in Mvars) are within the design capability of the Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Generating Facility for an under or over frequency condition in accordance with Good Utility Practice and Applicable Reliability Standards.

9.6.3 Payment for Reactive Power. Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Generating Facility when Transmission Owner requests Interconnection Customer to operate its Generating Facility outside the
range specified in Article 9.6.1. Payments shall be pursuant to Article 11.68 or such other agreement to which the Parties have otherwise agreed; provided however, to the extent the Tariff contains a provision providing for such compensation, that Tariff provision shall control.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to all Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Parties of such removal.

9.7.1.2 Outage Schedules. Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 Outage Restoration. If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects another Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Parties, to the extent such information is known, information on
the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 Interruption of Service. If required by Good Utility Practice to do so, Transmission Provider and/or Transmission Owner may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's and/or Transmission Owner’s ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider or Transmission Owner shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Owner;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 Under-Frequency and Over Frequency Conditions. The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the
Transmission System. Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a generating facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 System Protection Facilities. Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Owner shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Owner’s Interconnection Facilities or the Transmission System as a result of the interconnection of the Generating Facility and the Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.
9.7.5 Requirements for Protection. In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Owner’s equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Generating Facility.

9.7.6 Power Quality. No Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.8 Switching and Tagging Rules. Each Party shall provide the other Parties a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Owner’s Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon
methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Generating Facility or the Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

Article 10. Maintenance

10.1 Transmission Owner Obligations. Transmission Owner shall maintain the Transmission System and Transmission Owner’s Interconnection Facilities in a safe and reliable manner and in accordance with this GIA.

10.2 Interconnection Customer Obligations. Interconnection Customer shall maintain the Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA.

10.3 Coordination. The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Generating Facility and the Interconnection Facilities.

10.4 Secondary Systems. Each Party shall cooperate with the others in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact another Party. Each Party shall provide advance notice to the other Parties before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Owner’s Interconnection Facilities.
Article 11. Performance Obligation

11.1 Interconnection Customer Interconnection Facilities. Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer’s Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 Generating Facility. Interconnection Customer shall install the Generating Facilities described in Appendix C within three (3) years of the Commercial Operation Date(s) specified in Appendix B.

11.3 Transmission Owner’s Interconnection Facilities. Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Owner’s Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

11.4 Network Upgrades and Distribution Upgrades. All Network Upgrades and Distribution Upgrades described in Appendix A shall be constructed in accordance with the process set forth in Section VI of Attachment O. Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades that are associated with that Transmission Owner’s system. The Distribution Upgrades and Network Upgrades described in Appendix A shall be solely funded by Interconnection Customer unless Transmission Owner elects to fund the capital for the Distribution Upgrades or Network Upgrades.

11.4.1 Agreement to Fund Shared Network Upgrades. Interconnection Customer agrees to fund Shared Network Upgrades, as determined by Transmission Provider. Where applicable, payments to fund Shared Network Upgrade(s) that are made to Transmission Provider by Interconnection Customer will be disbursed by Transmission Provider to the appropriate entities that are constructing the Shared Network Upgrades in accordance with Attachment O of the Tariff. In the event that Interconnection Customer fails to meet its obligation to fund Shared Network Upgrades, Transmission Owner and Transmission Provider shall not be responsible for the Interconnection Customer’s funding obligation.

11.4.2 Contingencies Affecting Network Upgrades, System Protection Facilities and Distribution Upgrades. Network Upgrades, System Protection Facilities and Distribution Upgrades that are required to accommodate the Generating Facility may be modified because (a) a higher queued Interconnection Request withdrew or was deemed to have withdrawn, (b) the GIA associated with a higher queued Interconnection Request was terminated, (c) changes occur in equipment design standards or reliability criteria giving rise to the need for restudy, or (d) in accordance with Article 11.6.2, a lower queued interconnection customer has elected to move its queue priority ahead of the Interconnection Customer. The higher queued Interconnection Requests that could impact...
the Network Upgrades, System Protection Facilities and Distribution Upgrades required to accommodate the Generating Facility, and possible modifications that may result from the above listed events affecting the higher queued Interconnection Requests, to the extent such modifications are reasonably known and can be determined, and estimates of the costs associated with such required Network Upgrades, System Protection Facilities and Distribution Upgrades, shall be provided in Appendix A.

11.4.3 Agreement to Restudy. The Interconnection Customer agrees to allow the Transmission Provider to perform a restudy in accordance with Sections 8.8 and 8.13 of the GIP if the Transmission Provider determines a restudy is required because one or more of the contingencies in Article 11.4.2 occurred. If a restudy is required, the Transmission Provider shall provide notice to Interconnection Customer. The Parties agree to amend Appendix A to this GIA in accordance with Article 30.10 to reflect the results of the restudy.

11.5 Transmission Credits.

11.5.4 Credits for Amounts Advanced for Network Upgrades. Interconnection Customer shall be entitled to credits in accordance with Attachment Z2 of the Tariff for any Network Upgrades including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection Customer pursuant to Article 5.17.8.

11.5.2 Special Provisions for Affected Systems. Unless Transmission Provider provides, under the GIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

11.5.3 Notwithstanding any other provision of this GIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain transmission credits for transmission service that is not associated with the Generating Facility.

11.6 Initial Payment.

Interconnection Customer shall make an initial payment (“Initial Payment”) equal to the greater of a) twenty (20) percent of the total cost of Network Upgrades, Shared Network Upgrades, Transmission Owner Interconnection Facilities and/or Distribution Upgrades
listed in Appendix A or b) $4,000/MW of the size of the Generating Facility. Any remaining milestone deposits provided in Section 8.2 and Section 8.9 of the GIP will be applied to this requirement. The Initial Payment shall be provided to Transmission Owner or Transmission Provider as required in Appendix B by Interconnection Customer pursuant to this Article 11.6 within the later of a) thirty (30) days of the execution of the GIA by all Parties, or b) thirty (30) days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by Interconnection Customer, or c) thirty (30) days of the filing if the GIA is filed unexecuted and the Initial Payment is not being protested by Interconnection Customer. The Interconnection Customer may agree to make this Initial Payment non-refundable in accordance with Article 11.6.2. If this GIA is terminated, then the Initial Payment shall be refunded to the Interconnection Customer less:

a. any costs that have been incurred for the construction of the facilities specified in Appendix A;

b. any funds necessary for the construction of those Shared Network Upgrades, or Network Upgrades, that would be assigned to another interconnection customer where such upgrade costs would not have been assigned but for the termination of the GIA; and

c. any costs that have been incurred for the construction of those Shared Network Upgrades, or Network Upgrades, that are no longer required due to the termination of the GIA that were paid for by another interconnection customer.

11.6.1 If the Interconnection Customer has stated its intent to use the existing interconnection capacity of the Transmission System in order to achieve its Commercial Operation Date, the Interconnection Customer will provide the greater of a) one hundred (100) percent of the total cost of Network Upgrades, Shared Network Upgrades, Transmission Owner Interconnection Facilities and/or Distribution Upgrades listed in Appendix A or b) $4,000/MW of the size of the Generating Facility. The milestone deposits provided in Section 8.2 and Section 8.9 of the GIP will be applied to this requirement. The initial payment shall be provided to Transmission Owner or Transmission Provider as required in Appendix B by Interconnection Customer pursuant to this Article 11.6 within the later of a) thirty (30) days of the execution of the GIA by all Parties, or b) thirty (30) days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by Interconnection Customer, or c) thirty (30) days of the filing if the GIA is filed unexecuted and the initial payment is not being protested by Interconnection Customer. This payment is not refundable upon termination of the GIA unless the higher queued interconnection customer chooses to retain its current scope of Network Upgrades by agreeing to make its initial payment non-refundable in accordance with this GIA. These funds will be applied to the Network Upgrades assigned to the Interconnection Customer.
11.6.2 If another interconnection customer has notified the Transmission Provider in writing of its intent to use the existing interconnection capacity of the Transmission System in accordance with its GIA, the Interconnection Customer shall be subject to a restudy in accordance with Article 11.4.2(d) to determine the new scope of Network Upgrades unless the Interconnection Customer notifies the Transmission Provider within 30 Calendar Days of the notice from Transmission Provider of its intent to retain the Network Upgrades listed in Appendix A and agrees to make its Initial Payment in Article 11.6 non-refundable and authorizes engineering, procurement, and construction of those Network Upgrades in accordance with Article 5.5 and Article 5.6. Upon receipt of this authorization, the applicable dates in Appendix B shall be revised by the Parties. The Interconnection Customer continues to be subject to restudy conditions in Article 11.4.2(a-c).

11.5 Provision of Security. At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades as defined in Appendix A of this GIA, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the costs for constructing, procuring and installing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades as defined in Appendix A of this GIA and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider or Transmission Owner for these purposes. If Interconnection Customer requests suspension pursuant to Article 5.16, Interconnection Customer may be required to provide Transmission Provider security in the form described above for its allocated share of Network Upgrade(s) costs as calculated pursuant to Section 4.2.5 of the GIP and defined in Appendix A of this GIA.

In addition:

11.75.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.75.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.75.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.86 Interconnection Customer Compensation. If Transmission Provider or Transmission Owner requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this GIA, Transmission
Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to the Tariff. Interconnection Customer shall serve Transmission Provider with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this GIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

11.86.1 Interconnection Customer Compensation for Actions During Emergency Condition. Transmission Provider shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.86.

Article 12. Invoice

The terms of this Article 12 apply to billing between the Parties for construction and operation and maintenance charges. All other billing will be handled according to the Tariff.

12.1 General. Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this GIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice. Within six months after completion of the construction of Interconnection Facilities and the Network Upgrades, the Interconnection Customer shall receive an invoice of the final cost due under this GIA, including any applicable cost due to termination, which shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Interconnection Customer shall receive a refund of any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this GIA.
12.4 **Disputes.** In the event of a billing dispute between the Parties, Transmission Owner, and Transmission Provider shall continue to provide Interconnection Service under this GIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Owner or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Owner may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC’s regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

Article 13. **Emergencies**

13.1 **Definition.** “Emergency Condition” shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, Transmission Owner’s Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Generator Interconnection Agreement to possess black start capability.

13.2 **Obligations.** Each Party shall comply with the Emergency Condition procedures of NERC, the Applicable Reliability Council, Transmission Provider, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

13.3 **Notice.** Transmission Provider or Transmission Owner shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Owner’s Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider and Transmission Owner promptly when it becomes aware of an Emergency Condition that affects the Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Owner’s Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Owner’s facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.
13.4 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Owner, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or Transmission Owner or otherwise regarding the Transmission System.

13.5 Transmission Provider and Transmission Owner Authority.

13.5.1 General. Transmission Provider and/or Transmission Owner may take whatever actions or inactions with regard to the Transmission System or Transmission Owner’s Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Owner’s Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider and Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider and/or Transmission Owner may, on the basis of technical considerations, require the Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's and Transmission Owner’s operating instructions concerning Generating Facility real power and reactive power output within the manufacturer's design limitations of the Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 Reduction and Disconnection. Transmission Provider and/or Transmission Owner may reduce Interconnection Service or disconnect the Generating Facility or Interconnection Customer's Interconnection Facilities, when such reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When Transmission Provider and/or Transmission Owner can schedule the reduction or disconnection in advance, Transmission Provider and/or Transmission Owner shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider and/or Transmission Owner shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least
impact to Interconnection Customer, Transmission Provider and/or Transmission Owner. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.6 Interconnection Customer Authority. Consistent with Good Utility Practice and the GIA and the GIP, Interconnection Customer may take actions or inactions with regard to the Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Owner’s Interconnection Facilities. Transmission Provider and/or Transmission Owner shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 Limited Liability. Except as otherwise provided in Article 11.6 of this GIA, no Party shall be liable to the other Parties for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

Article 14. Regulatory Requirements and Governing Law

14.1 Regulatory Requirements. Each Party's obligations under this GIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this GIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act the Public Utility Holding Company Act of 2005, or the Public Utility Regulatory Policies Act of 1978 as amended by the 2005 Energy Policy Act.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this GIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This GIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

Article 15. Notices.
15.1 General. Unless otherwise provided in this GIA, any notice, demand or request required or permitted to be given by any Party to another and any instrument required or permitted to be tendered or delivered by any Party in writing to another shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Any Party may change the notice information in this GIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by any Party to another and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Parties in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

Article 16. Force Majeure

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 No Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Parties in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

Article 17. Default

17.1 Default.
17.1.1 General. No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this GIA or the result of an act or omission of another Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Right to Terminate. If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this GIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this GIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this GIA.

Article 18. Indemnity, Consequential Damages and Insurance

18.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Parties’ action or inactions of its obligations under this GIA on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

18.1.1 Indemnified Person. If an indemnified person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 Indemnifying Party. If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 18, the amount owing to the indemnified person shall be the amount of such indemnified person’s actual Loss, net of any insurance or other recovery.

18.1.3 Indemnity Procedures. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party’s
indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

18.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall any Party be liable to any other Party under any provision of this GIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which any Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance. Interconnection Customer and Transmission Owner shall at their own expense, maintain in force throughout the period of this GIA, and until released by all other Parties, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located. The minimum limits for the Employers' Liability insurance shall be One Million Dollars ($1,000,000) each accident
bodily injury by accident, One Million Dollars ($1,000,000) each employee
bodily injury by disease, and One Million Dollars ($1,000,000) policy limit bodily
injury by disease.

18.3.2 Commercial General Liability Insurance including premises and operations,
personal injury, broad form property damage, broad form blanket contractual
liability coverage (including coverage for the contractual indemnification)
products and completed operations coverage, coverage for explosion, collapse and
underground hazards (if applicable), independent contractors coverage, coverage
for pollution (if exposure is present) and punitive or exemplary damages, with
minimum limits of One Million Dollars ($1,000,000) each occurrence/Two
Million Dollars ($2,000,000) general aggregate and Two Million Dollars
($2,000,000) products and completed operations aggregate combined single limit
for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-
owned and hired vehicles, trailers or semi-trailers designed for travel on public
roads, with a minimum, combined single limit of One Million Dollars
($1,000,000) per occurrence for bodily injury, including death, and property
damage.

18.3.4 Excess Liability Insurance over and above the Employers' Liability Commercial
General Liability and Comprehensive Automobile Liability Insurance coverage,
with a minimum combined single limit of Twenty Million Dollars ($20,000,000)
each occurrence/Twenty Million Dollars ($20,000,000) general aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile
Insurance and Excess Public Liability Insurance policies shall name the other
Party, its parent, associated and Affiliate companies and their respective directors,
officers, agents, servants and employees ("Other Party Group") as additional
insured. All policies shall contain provisions whereby the insurers waive all
rights of subrogation in accordance with the provisions of this GIA against the
Other Party Group and provide thirty (30) Calendar Days advance written notice
to the Other Party Group prior to anniversary date of cancellation or any material
change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile
Liability Insurance and Excess Public Liability Insurance policies shall contain
provisions that specify that the policies are primary and shall apply to such extent
without consideration for other policies separately carried and shall state that each
insured is provided coverage as though a separate policy had been issued to each,
except the insurer's liability shall not be increased beyond the amount for which
the insurer would have been liable had only one insured been covered. Each
Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile
Liability Insurance and Excess Public Liability Insurance policies, if written on a
Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this GIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed to by all Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Interconnection Customer and Transmission Owner are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

18.3.9 Within ten (10) days following execution of this GIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, Interconnection Customer and Transmission Owner shall provide certification of all insurance required in this GIA, executed by each insurer or by an authorized representative of each insurer to the Other Party Group.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this GIA.

Article 19. Assignment

19.1 Assignment. This GIA may be assigned by any Party only with the written consent of the other Parties; provided that any Party may assign this GIA without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this GIA; and provided further that Interconnection Customer shall have the right to assign this GIA, without the consent of Transmission Provider or Transmission Owner, for collateral security purposes to aid in providing financing for the Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider and Transmission Owner of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider and Transmission Owner of the date and
particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.7 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this GIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

Article 20. Severability

20.1 Severability. If any provision in this GIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this GIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Owner) seeks and obtains such a final determination with respect to any provision of the Negotiated Option (Article 5.1.3), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

Article 21. Comparability

21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

Article 22. Confidentiality

22.1 Confidentiality. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to another prior to the execution of this GIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by any Party, a Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term. During the term of this GIA, and for a period of three (3) years after the expiration or termination of this GIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.
22.1.2 **Scope.** Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this GIA; or (6) is required, in accordance with Article 22.1.7 of the GIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this GIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 **Release of Confidential Information.** No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this GIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 **Rights.** Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses another other Party. The disclosure by any Party to another Party of Confidential Information shall not be deemed a waiver by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 **No Warranties.** By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to another Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 **Standard of Care.** Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to another Party under this GIA or its regulatory requirements.
22.1.7 Order of Disclosure. If a court or a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires a Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of this GIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 Termination of Agreement. Upon termination of this GIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 Remedies. In the instance where Transmission Owner is a Federal Power Agency, as specified in the opening paragraph of this Agreement, then this Section 22.1.9 shall not apply to Transmission Owner. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 Disclosure to FERC, its Staff, or a State. Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 C.F.R. Section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this GIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. Section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying another Party to this GIA
prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to the GIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. Section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this GIA ("Confidential Information") shall not be disclosed by another Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this GIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

22.1.12 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

Article 23. Environmental Releases

23.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

Article 24. Information Requirements

24.1 Information Acquisition. Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective
facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 **Information Submission by Transmission Provider.** The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

**Article 25. Information Access and Audit Rights**

25.1 **Information Access.** Each Party (the "disclosing Party") shall make available to the other Parties information that is in the possession of the disclosing Party and is necessary in order for the other Parties to: (i) verify the costs incurred by the disclosing Party for which the other Parties are responsible under this GIA; and (ii) carry out its obligations and responsibilities under this GIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this GIA.

25.2 **Reporting of Non-Force Majeure Events.** Each Party (the "notifying Party") shall notify the other Parties when the notifying Party becomes aware of its inability to comply with the provisions of this GIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Parties receiving such notification to allege a cause for anticipatory breach of this GIA.

25.3 **Audit Rights.** Subject to the requirements of confidentiality under Article 22 of this GIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to another Party, to audit at its own expense that other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this GIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of
obligations under this GIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Transmission Owner’s Interconnection Facilities, and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Owner’s issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to any Party’s performance or satisfaction of all obligations under this GIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party’s receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

25.5 Audit Results. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

Article 26. Subcontractors

26.1 General. Nothing in this GIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this GIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this GIA in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

26.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this GIA. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Owner be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this GIA. Any applicable obligation imposed by this GIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

Article 27. Disputes
27.1 Submission. In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with this GIA or its performance, the Parties agree to resolve such dispute using the dispute resolution procedures of the Tariff.

Article 28. Representations, Warranties, and Covenants

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this GIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this GIA.

28.1.2 Authority. Such Party has the right, power and authority to enter into this GIA, to become a Party hereto and to perform its obligations hereunder. This GIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 No Conflict. The execution, delivery and performance of this GIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this GIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this GIA, and it will provide to any Governmental Authority notice of any actions under this GIA that are required by Applicable Laws and Regulations.

Article 29. Joint Operating Committee

29.1 Joint Operating Committee. At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer, Transmission Owner and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Party shall notify the other Parties of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the
request of any Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this GIA. All Parties shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

29.1.1 Establish data requirements and operating record requirements.

29.1.2 Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

29.1.3 Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Owner’s and Interconnection Customer's facilities at the Point of Interconnection.

29.1.4 Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Generating Facility and other facilities that impact the normal operation of the interconnection of the Generating Facility to the Transmission System.

29.1.5 Ensure that information is being provided by each Party regarding equipment availability.

29.1.6 Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

Article 30. Miscellaneous

30.1 Binding Effect. This GIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this GIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this GIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. This GIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this GIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this GIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable,
rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this GIA or such Appendix to this GIA, or such Section to the GIP or such Appendix to the GIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this GIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 **Entire Agreement.** This GIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, among the Parties with respect to the subject matter of this GIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, a Party's compliance with its obligations under this GIA.

30.5 **No Third Party Beneficiaries.** This GIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 **Waiver.** The failure of a Party to this GIA to insist, on any occasion, upon strict performance of any provision of this GIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by a Party of its rights with respect to this GIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this GIA. Termination or Default of this GIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this GIA shall, if requested, be provided in writing.

30.7 **Headings.** The descriptive headings of the various Articles of this GIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this GIA.

30.8 **Multiple Counterparts.** This GIA may be executed in three or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 **Amendment.** The Parties may by mutual agreement amend this GIA by a written instrument duly executed by each of the Parties.

30.10 **Modification by the Parties.** The Parties may by mutual agreement amend the Appendices to this GIA by a written instrument duly executed by the Parties. Such
amendment shall become effective and a part of this GIA upon satisfaction of all Applicable Laws and Regulations.

### 30.11 Reservation of Rights

Transmission Provider shall have the right to make a unilateral filing with FERC to modify this GIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this GIA pursuant to Section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this GIA shall limit the rights of the Parties or of FERC under Sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

### 30.12 No Partnership

This GIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.
IN WITNESS WHEREOF, the Parties have executed this GIA in triplicate originals, each of which shall constitute and be an original effective Agreement among the Parties.

SOUTHWEST POWER POOL, INC.
By: ________________________ Title: ________________________
Date: ________________________

[Insert name of Transmission Owner]
By: ________________________
Title: ________________________
Date: ________________________

[Insert name of Interconnection Customer]
By: ________________________
Title: ________________________
Date: ________________________
APPENDIX A TO GIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. Interconnection Facilities:
   
   (a) [insert Interconnection Customer's Interconnection Facilities]:
   
   (b) [insert Transmission Provider's Interconnection Facilities]:

2. Network Upgrades:
   
   (a) [insert Stand Alone Network Upgrades]:
   
   (b) [insert Other Network Upgrades]:
   
   (be) [insert Shared Network Upgrades]:
   
   (cd) [insert Previous Network Upgrades]

3. Distribution Upgrades:

4. Interconnection Service:
   
   Interconnection Customer has requested the following (from Appendix 1 of the GIP):
   
   _____ Energy Resource Interconnection Service
   _____ Network Resource Interconnection Service

5. Construction Option Selected by Customer

6. Permits, Licenses, and Authorizations

7. Description of the Point of Change of Ownership

8. Description of the Point of Interconnection

9. Higher-Queued Interconnection Customers
Appendix B to GIA

Milestones
1. Description of Generating Facility:

Wind Generating Facility Output Reduction

To protect the reliability of the Transmission System, a Generating Facility that is a wind plant shall be capable of reducing its generation output in increments of no more than fifty (50) MW in five (5) minute intervals. The requirements may be met by using: (a) SCADA control of circuit breakers protecting wind farm collector distribution circuits, (b) automatic control of wind turbine power output, or (c) a combination of (a) and (b).
Appendix D to GIA

Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.
Appendix E to GIA

Commercial Operation Date

[Date]

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

[Transmission Owner Address]

Re: _____________ Generating Facility

Dear _______________:

On [Date] [Interconnection Customer] has completed Trial Operation of Unit No. ___. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. ___ at the Generating Facility, effective as of [Date plus one day].

Thank you.

[Signature]

[Interconnection Customer Representative]
Appendix F to GIA

ADDRESSES FOR DELIVERY OF NOTICES AND BILLINGS

Notices:

Transmission Provider:

____________________________, __________________________
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

Transmission Owner:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Billings and Payments: [Specify addresses for construction invoices, O&M invoices and settlement of ancillary services]

Transmission Provider:

____________________________, __________________________
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

Transmission Owner:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

____________________________, __________________________
Southwest Power Pool, Inc.
201 Worthen Drive
Transmission Owner:
[To be supplied.]

Interconnection Customer:
[To be supplied.]

Operational Communications: [Identify contacts for operations]

Transmission Provider:

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Phone: ______________________
Facsimile: 501-482-2022

Transmission Owner:
[To be supplied.]

Interconnection Customer:
[To be supplied.]
Appendix G to GIA

REQUIREMENTS OF GENERATORS RELYING ON NEWER TECHNOLOGIES

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this GIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or “GSU”), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

**Post-transition Period LVRT Standard**

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. **Power Factor Design Criteria (Reactive Power)**

A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this GIA, if the Transmission Provider’s System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

iii. **Supervisory Control and Data Acquisition (SCADA) Capability**

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for
the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Effective Date: 1/15/2013 - Docket #: ER13-406-000
APPENDIX 7 TO GIP

INTERCONNECTION PROCEDURES FOR A WIND GENERATING PLANT

Appendix 7 sets forth procedures specific to a wind generating plant. All other requirements of this GIP continue to apply to wind generating plant interconnections.

A. **Special Procedures Applicable to Wind Generators**

The wind plant Interconnection Customer, in completing the Interconnection Request required by Section 3.3 of this GIP, may provide to the Transmission Provider a set of preliminary electrical design specifications depicting the wind plant as a single equivalent generator. Upon satisfying these and other applicable Interconnection Request conditions, the wind plant may enter the queue and receive the base case data as provided for in this GIP.

Before returning either the Preliminary Interconnection System Impact Study Agreement or the Definitive Interconnection System Impact Study Agreement, the wind plant Interconnection Customer must submit completed detailed electrical design specifications and other data (including collector system layout data) needed to allow the Transmission Provider to complete the System Impact Study.
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INTERIM GENERATOR INTERCONNECTION AGREEMENT

THIS INTERIM GENERATOR INTERCONNECTION AGREEMENT (“Agreement” or “Interim GIA”) is made and entered into this ___ day of ___________, by and among ___________________, a ____________ organized and existing under the laws of the State/Commonwealth of ___________ ("Interconnection Customer" with a Generating Facility), Southwest Power Pool, Inc., a corporation organized and existing under the laws of the State of Arkansas (“Transmission Provider”) and ______________, a ____________ organized and existing under the laws of the State/Commonwealth of ___________ ("Transmission Owner"). Interconnection Customer, Transmission Provider and Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

Recitals

WHEREAS, Transmission Provider functionally controls the operation of the Transmission System; and,

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Transmission Owner owns facilities to which the Generating Facility is to be interconnected and may be constructing facilities to allow the interconnection; and,

WHEREAS, Transmission Provider has posted on its website a Definitive Interconnection System Impact Study that included the Interconnection Customer’s Generating Facility and has conducted an additional analysis to determine the availability of Interim Interconnection Service at the time of the Interconnection Customer’s requested In-Service Date and Commercial Operation Date with the Transmission System topology and in-service generation expected to be in place at that time; and,

WHEREAS, Interconnection Customer, in accordance with Section 11A.2.1 of the Generator Interconnection Procedures (“GIP”), has provided Transmission Provider with reasonable evidence of Site Control or additional security and with reasonable evidence that one or more of the milestones listed in Section 11A.2.1 has been achieved; and

WHEREAS, Interconnection Customer, Transmission Provider and Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Generating Facility with the Transmission System on an interim basis prior to the completion of the generator interconnection study process set forth in the GIP and execution of a Generator Interconnection Agreement;
NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Interim GIA, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (“Tariff”).

Article 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Interim Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Interim Generator Interconnection Agreement.
Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting Interconnection Studies.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Interim Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Interim Generator Interconnection Agreement.

Definitive Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in a Preliminary Interconnection System Impact Study or that may be caused by the withdrawal or addition of an Interconnection Request, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Generator Interconnection Procedures.

Definitive Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3A of the Generator Interconnection Procedures for conducting the Definitive Interconnection System Impact Study.

Definitive Interconnection System Impact Study Queue shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for a Definitive Interconnection System Impact Study.
**Dispute Resolution** shall mean the procedure in Section 12 of the Tariff for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

**Distribution System** shall mean the Transmission Owner’s facilities and equipment that are not included in the Transmission System. The voltage levels at which Distribution Systems operate differ among areas.

**Distribution Upgrades** shall mean the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

**Effective Date** shall mean the date on which the Interim Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

**Emergency Condition** shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System or the electric systems of others to which the Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Owner’s Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by Interim Generator Interconnection Agreement to possess black start capability.

**Energy Resource Interim Interconnection** Service shall mean an Interim Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

**Engineering & Procurement (E&P) Agreement** shall mean an agreement that authorizes the Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

**Environmental Law** shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Generator Interconnection Agreement (GIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility that is included in the Transmission Provider's Tariff.

Generator Interconnection Procedures (GIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility that are included in the Transmission Provider's Tariff.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, Transmission Owner or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials,"
"hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

**Higher Queued Projects** shall mean those projects specifically identified as “Higher Queued Projects” in Appendix A.

**Initial Synchronization Date** shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

**In-Service Date** shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Owner's Interconnection Facilities to obtain back feed power.

**Interconnection Customer** shall mean any entity, including the Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission System.

**Interconnection Customer's Interconnection Facilities** shall mean all facilities and equipment, as identified in Appendix A of the Interim Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

**Interconnection Facilities** shall mean the Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

**Interconnection Facilities Study** shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Definitive Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission System. The scope of the study is defined in Section 8 of the Generator Interconnection Procedures.

**Interconnection Facilities Study Agreement** shall mean the form of agreement contained in Appendix 4 of the Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

**Interconnection Facilities Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for an Interconnection Facilities Study.
**Interconnection Feasibility Study** shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission System, the scope of which is described in Section 6 of the Generator Interconnection Procedures.

**Interconnection Feasibility Study Agreement** shall mean the form of agreement contained in Appendix 2 of the Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

**Interconnection Feasibility Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for an Interconnection Feasibility Study.

**Interconnection Queue Position** shall mean the order of a valid Interconnection Request within the Interconnection Facilities Study Queue, relative to all other pending valid Interconnection Requests within the Interconnection Facilities Study Queue, which is established based upon the requirements in Section 4.1.3 of the Generator Interconnection Procedures.

**Interconnection Request** shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission System.

**Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Generator Interconnection Agreement and, if applicable, the Tariff.

**Interconnection Study** shall mean any of the following studies: the Interconnection Feasibility Study, the Preliminary Interconnection System Impact Study, the Definitive Interconnection System Impact Study, the Interim Availability Interconnection System Impact Study, and the Interconnection Facilities Study described in the Generator Interconnection Procedures.

**Interconnection Study Agreement** shall mean any of the following agreements: the Interconnection Feasibility Study Agreement, the Preliminary Interconnection System Impact Study Agreement, the Definitive Interconnection System Impact Study Agreement, the Interim Availability Interconnection System Impact Study Agreement, and the Interconnection Facilities Study Agreement described in the Generator Interconnection Procedures.

**Interim Availability Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Transmission System and, if applicable, an Affected System for the purpose of providing Interim Interconnection Service. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications on an interim basis.
**Interim Availability Interconnection System Impact Study Agreement** shall mean the form of agreement contained in Appendix 5 of the Generator Interconnection Procedures for conducting the Interim Availability Interconnection System Impact Study.

**Interim Generator Interconnection Agreement (Interim GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility to allow interconnection to the Transmission System prior to the completion of the Interconnection Study process.

**Interim Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interim Generator Interconnection Agreement and, if applicable, the Tariff.

**IRS** shall mean the Internal Revenue Service.

**Joint Operating Committee** shall be a group made up of representatives from Interconnection Customer, Transmission Owner and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

**Loss** shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Interim Generator Interconnection Agreement, on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

**Material Modification** shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

**Metering Equipment** shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Interim Generator Interconnection Agreement, at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

**NERC** shall mean the North American Electric Reliability Corporation or its successor organization.

**Network Resource** shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.
Network Resource Interim Interconnection Service shall mean an Interim
Interconnection Service that allows the Interconnection Customer to integrate its Generating
Facility with the Transmission System in a manner comparable to that in which the Transmission
Owner integrates its generating facilities to serve Native Load Customers as a Network
Resource. Network Resource Interim Interconnection Service in and of itself does not convey
transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the
Transmission System required at or beyond the point at which the Interconnection Facilities
connect to the Transmission System to accommodate the interconnection of the Generating
Facility to the Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in
connection with the Interim Generator Interconnection Agreement, or its performance.

Party or Parties shall mean Transmission Provider, Transmission Owner,
Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the
Interim Generator Interconnection Agreement, where the Interconnection Customer's
Interconnection Facilities connect to the Transmission Owner's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Interim
Generator Interconnection Agreement, where the Interconnection Facilities connect to the
Transmission System.

Preliminary Interconnection System Impact Study shall mean an engineering study
that evaluates the impact of the proposed interconnection on the safety and reliability of
Transmission System and, if applicable, an Affected System. The study shall identify and detail
the system impacts that would result if the Generating Facility were interconnected without
project modifications or system modifications, focusing on the Adverse System Impacts
identified in an Interconnection Feasibility Study or that may be caused by an Interconnection
Request, or to study potential impacts, including but not limited to those identified in the
Scoping Meeting as described in the Generator Interconnection Procedures.

Preliminary Interconnection System Impact Study Agreement shall mean the form of
agreement contained in Appendix 3 of the Generator Interconnection Procedures for conducting
the Preliminary Interconnection System Impact Study.

Preliminary Interconnection System Impact Study Queue shall mean a Transmission
Provider separately maintained queue for valid Interconnection Requests for a Preliminary
Interconnection System Impact Study.

Previous Network Upgrade shall mean a Network Upgrade that is needed for the
interconnection of one or more Interconnection Customers’ Generating Facilities, but is not the
cost responsibility of the Interconnection Customer, subject to restudy, and which is identified in
Appendix A of the Generator Interconnection Agreement.
Queue shall mean the Interconnection Feasibility Study Queue, the Preliminary Interconnection System Impact Study Queue, or the Definitive Interconnection System Impact Study Queue, or the Interconnection Facilities Study Queue, as applicable.

Queue Position shall mean the order of a valid Interconnection Request within the Interconnection Feasibility Study Queue, relative to all other pending valid Interconnection Requests within the Interconnection Feasibility Study Queue, the order of a valid Interconnection Request within the Preliminary Interconnection System Impact Study Queue, relative to all other pending valid Interconnection Requests within the Preliminary Interconnection System Impact Study Queue, or the order of a valid Interconnection Request within the Definitive Interconnection System Impact Study Queue, relative to all other pending valid Interconnection Requests within the Definitive Interconnection System Impact Study Queue, as applicable, that is established based upon the date and time of receipt of the valid Interconnection Request and the date and time of receipt of other information specified under Section 4.1 of this GIP, as applicable, by the Transmission Provider.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Interim Generator Interconnection Agreement efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer, Transmission Owner and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Shared Network Upgrade shall mean a Network Upgrade listed in Appendix A of the Generator Interconnection Agreement that is needed for the interconnection of multiple Interconnection Customers’ Generating Facilities and which is the shared funding responsibility of such Interconnection Customers that may also benefit other Interconnection Customer(s) that are later identified as beneficiaries.

Site Control shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site of sufficient size for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site of sufficient size for such purpose.

Small Generating Facility shall mean a Generating Facility that has an aggregate net Generating Facility Capacity of no more than 2 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. The Transmission Provider, Transmission Owner and the
Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Interim Generator Interconnection Agreement.

**System Protection Facilities** shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission System or on other delivery systems or other generating systems to which the Transmission System is directly connected.

**Tariff** shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

**Transmission Owner** shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Interim Generator Interconnection Agreement to the extent necessary.

**Transmission Provider** shall mean the public utility (or its Designated Agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

**Transmission Owner's Interconnection Facilities** shall mean all facilities and equipment owned, controlled or operated by the Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Interim Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades Stand Alone Network Upgrades or Network Upgrades.

**Transmission System** shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

**Trial Operation** shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

**Article 2. Effective Date, Term, and Termination**

2.1 **Effective Date.** This Interim GIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this Interim GIA with FERC upon execution in accordance with Article 3.1, if required.
2.2 **Term of Agreement.** This Interim GIA shall remain in effect from its Effective Date until the earliest occurrence of one of the termination events described in Article 2.3.1.

2.3 **Termination Procedures.**

2.3.1 **Termination Events.**

2.3.1.1 This Interim GIA may be terminated by Interconnection Customer after giving Transmission Provider and Transmission Owner ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.1.2 This Interim GIA shall terminate upon occurrence of one or more of the following events:

(a) The Effective Date of a GIA regarding the Generating Facility that is the subject of this Interim GIA that has been accepted by FERC and/or reported in Transmission Provider’s Electric Quarterly Report;

(b) The date of a FERC order rejecting an unexecuted GIA regarding the Generating Facility that is the subject of this Interim GIA;

(c) The date the Interconnection Customer’s Interconnection Request is deemed withdrawn pursuant to the GIP;

(d) The Interconnection Customer’s failure to pay part or all of the required security pursuant to Article 11.5; or

(e) The Transmission Provider’s determination in accordance with Article 4.2.2, that Interim Interconnection Service to Interconnection Customer and the amount of power that Interconnection Customer is permitted to inject into the Transmission System from its Generating Facility pursuant to this Interim GIA is reduced to zero.

2.3.2 **Default.** Any Party may terminate this Interim GIA in accordance with Article 17.

2.3.3 Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this Interim GIA, which notice has been accepted for filing by FERC.

2.3.4 Upon termination of this Interim GIA for any reason, Interim Interconnection Service under this Interim GIA shall cease and the provisions of Section 11A.5 of the GIP shall apply.
2.4 Termination Costs.

2.4.1 If this Interim GIA is terminated pursuant to Article 2.3.1.2(a), the cost responsibilities of Interconnection Customer and Transmission Owner pursuant to this Interim GIA will be included in the GIA regarding the Generating Facility that is the subject of this Interim GIA to the extent not satisfied during the term of this Interim GIA.

2.4.2 If this Interim GIA is terminated pursuant to Article 2.3 for any reason except as specified 2.3.1.2(a), Interconnection Customer and Transmission Owner shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment), and charges assessed by any other Party, as of the date of such Party's receipt of such notice of termination, that are the responsibility of the Terminating Party under this Interim GIA. In the event of termination by any Party, all Parties shall use Commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this Interim GIA, unless otherwise ordered or approved by FERC:

2.4.2.1 With respect to any portion of Transmission Owner's Interconnection Facilities that have not yet been constructed or installed, Transmission Owner shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Owner shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Owner for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Owner shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts.

If this Interim GIA is terminated pursuant to Article 2.3 for any reason except as specified in Article 2.3.1.2(a) Interconnection Customer shall be responsible for all costs incurred in association with the Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which Transmission Owner has incurred expenses and has not been reimbursed by Interconnection Customer and shall forfeit the security paid pursuant to Article 11.5 of this
Interim GIA up to the total of the costs and expenses listed in this paragraph.

2.4.2.2 Transmission Owner may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Owner shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.2.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this Interim GIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 Disconnection or Limitation of Output. If this Interim GIA is terminated pursuant to Article 2.3 and disconnection or limitation in generation output is required, then the Parties will take all appropriate steps to either disconnect the Generating Facility from the Transmission System or limit the amount of generation output that can be injected into the transmission system pursuant to Section 4.2.2, whichever is applicable. All costs required to effectuate such disconnection or limitation shall be borne by Interconnection Customer, unless such termination resulted from another Party's Default of this Interim GIA, which in such event the defaulting Party shall be responsible for such disconnection costs.

2.6 Survival. Except as provided in this Article 2.6, this Interim GIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this Interim GIA; to permit payments for any credits under this Interim GIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Interim GIA was in effect; and to permit each Party to have access to the lands of another Party pursuant to this Interim GIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

Article 3. Regulatory Filings

3.1 Filing. Transmission Provider shall file this Interim GIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this Interim GIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

Article 4. Scope of Service
4.1 Interim Interconnection Product Options. Interconnection Customer has selected the following (checked) type of Interim Interconnection Service:

4.1.1 Energy Resource Interim Interconnection Service.

4.1.1.1 The Product. Energy Resource Interim Interconnection Service allows Interconnection Customer to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interim Interconnection Service for the term of this Interim GIA, unless otherwise specified in Appendix A, Transmission Owner shall construct the facilities listed in Appendix A to this Interim GIA.

4.1.1.2 Transmission Delivery Service Implications. Under Energy Resource Interim Interconnection Service, Interconnection Customer will be eligible to inject power from the Generating Facility into and deliver power across the Transmission System on an "as available" basis. The Interconnection Customer's ability to inject its Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of the Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of Firm Point-To-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

4.1.2 Network Resource Interim Interconnection Service.

4.1.2.1 The Product. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Generating Facility in a manner comparable to that in which Transmission Owner integrates its generating facilities to serve Native Load Customers as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interim Interconnection Service for the term of this Interim GIA, Transmission Owner shall construct the facilities identified in Appendix A to this Interim GIA.

4.1.2.2 Transmission Delivery Service Implications. Network Resource Interim Interconnection Service allows Interconnection Customer's Generating Facility to be designated by any Network Customer under the Tariff on the Transmission System as a Network Resource, up to the Generating Facility's full output, on the same basis as existing Network Resources interconnected to the Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interim Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain
delivery of energy from the interconnected Interconnection Customer's Generating Facility in the same manner as it accesses Network Resources. A Generating Facility receiving Network Resource Interim Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or Firm Point-To-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interim Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Generating Facility to any particular load on the Transmission System without incurring congestion costs. In the event of transmission constraints on the Transmission System, Interconnection Customer's Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

The Network Resource Interim Interconnection Service studies are done in accordance with the process set out in Attachment Z1 of the Tariff. To the extent a Network Customer does designate the Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interim Interconnection Service, any future transmission service request for delivery from the Generating Facility within the Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Generating Facility be undertaken, regardless of whether or not such Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.
To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Generating Facility outside the Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

4.2 **Provision of Service.** Transmission Provider shall provide Interim Interconnection Service for the Generating Facility at the Point of Interconnection as specified below.

4.2.1 The provision of Interim Interconnection Service and pre-commercial operation testing pursuant to this Interim GIA are contingent upon the Interconnection Facilities, Network Upgrades, Distribution Upgrades, and other necessary facilities listed in the applicable section of Appendix A to this Interim GIA being completed and in service. In no event shall pre-commercial operation testing or Interim Interconnection Service be permitted until the Interconnection Facilities, Network Upgrades, Distribution Upgrades and any other necessary facilities listed in applicable section of Appendix A to this Interim GIA are complete and in service.

4.2.1.1 Pre-Commercial Operation Testing. Interconnection Customer shall be able to sync its Generating Facility and its Interconnection Customer’s Interconnection Facilities to the Transmission System for the purpose of testing pursuant to Article 6.1, once the applicable facilities described in Appendix A are complete and in service.

4.2.1.2 Interim Interconnection Service. Interconnection Customer shall be able to sync its Generating Facility and its Interconnection Customer’s Interconnection Facilities to the Transmission System for the purpose of receiving Interim Interconnection Service and operating its Generating Facility up to the maximum amount for this Interim GIA, as specified in Appendix A on an “as available” basis once the applicable facilities in Appendix A are in service.

4.2.2 Interim Interconnection Service and the amount of power that Interconnection Customer is permitted to inject into the Transmission System from its Generating Facility pursuant to this Interim GIA may be reduced in whole or in part in the event that:

(a) one or more Interconnection Customer(s) with a Higher Queued Project (as specified in Appendix A): (i) has executed or subsequently executes an Interim GIA or a GIA that has been accepted by the FERC and/or reported in Transmission Provider’s Electric Quarterly Report, or has an unexecuted Interim GIA or GIA filed with and accepted by the FERC for that Higher Queued Project and (ii) begins Commercial Operation of the Higher Queued Project during the term of this Interim GIA; and
(b) Transmission Provider at its sole discretion determines that Interim Interconnection Service and/or Interconnection Service cannot be provided simultaneously under this Interim GIA and to such other Interconnection Customer(s) under its Interim GIA(s) or final GIA(s) in an amount commensurate with the maximum amount specified in the respective agreements without additional Interconnection Facilities, Network Upgrades, or Distribution Upgrades.

4.2.3 Any such reduction pursuant to Article 4.2.2 will be based on the Queue Position priority of the Interconnection Customer’s Interconnection Request relative to the Queue Position priority of the Higher Queued Projects.

4.3 **Performance Standards.** Each Party shall perform all of its obligations under this Interim GIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this Interim GIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the Interim GIA and submit the amendment to FERC for approval.

4.4 **No Transmission Delivery Service.** The execution of this Interim GIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 **Interconnection Customer Provided Services.** The services provided by Interconnection Customer under this Interim GIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.68.

**Article 5. Interconnection Facilities Engineering, Procurement, and Construction**

5.1 **Options.** Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either the Option To Build as described under Article 5.1.2 or the Negotiated Option described under Article 5.1.3 if the Interconnection Customer and the Transmission Owner cannot reach agreement under the Standard Option described under Article 5.1.1, for completion of Transmission Owner's Interconnection Facilities and Network Upgrades as set forth in Appendix A, Interconnection Facilities and Network Upgrades, and such dates and selected option, as applicable, shall be set forth in Appendix B, Milestones.

5.1.1 **Standard Option.** Transmission Owner shall design, procure, and construct Transmission Owner’s Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Owner’s Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Owner shall not be required to undertake any action which is
inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Owner reasonably expects that it will not be able to complete Transmission Owner’s Interconnection Facilities, and Network Upgrades by the specified dates, Transmission Owner shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 **Option to Build.** If the dates designated by Interconnection Customer are not acceptable to Transmission Owner, Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.1. Transmission Owner and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.3 **Negotiated Option.** If Interconnection Customer elects not to exercise its option under Article 5.1.2, Option to Build, Interconnection Customer shall so notify Transmission Provider and Transmission Owner within thirty (30) Calendar Days, and the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection Customer) pursuant to which Transmission Owner is responsible for the design, procurement and construction of Transmission Owner’s Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Transmission Owner shall assume responsibility for the design, procurement and construction of Transmission Owner’s Interconnection Facilities and Network Upgrades pursuant to Article 5.1.1, Standard Option.

5.2 **General Conditions Applicable to Option to Build.** If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Owner;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network
Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Owner shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(4) Prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider and Transmission Owner a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider and Transmission Owner;

(5) At any time during construction, Transmission Owner shall have the right to gain unrestricted access to Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) At any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Owner, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider and Transmission Owner for claims arising from Interconnection Customer's construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) The Interconnection Customer shall transfer control of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Owner's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Owner not later than the Commercial Operation Date;

(10) Transmission Owner shall approve and accept for operation and maintenance Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information, and any other documents that are reasonably required by
Transmission Owner to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

5.3 **Liquidated Damages.** The actual damages to Interconnection Customer, in the event Transmission Owner’s Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Owner pursuant to subparagraph 5.1.3, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Owner to Interconnection Customer in the event that Transmission Owner does not complete any portion of Transmission Owner’s Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of Transmission Owner’s Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Owner has assumed responsibility to design, procure and construct. However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Owner’s Interconnection Facilities and Network Upgrades for which Transmission Owner has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Owner to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this GIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Owner’s failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Owner’s Interconnection Facilities or Network Upgrades to take the delivery of power for the Generating Facility's Trial Operation or to export power from the Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Owner’s Interconnection Facilities or Network Upgrades to take the delivery of power for Generating Facility's Trial Operation or to export power from the Generating Facility, but for Transmission Owner’s delay; (2) Transmission Owner’s failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into an Interim GIA or GIA with Transmission Owner or any cause beyond Transmission Owner’s reasonable control or reasonable ability to cure; (3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 **Power System Stabilizers.** The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed
Power System Stabilizers, subject to the design and operating limitations of the Generating Facility. If the Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Owner’s system operator, or its designated representative. The requirements of this paragraph shall not apply to wind generators.

5.5 **Equipment Procurement.** If responsibility for construction of Transmission Owner’s Interconnection Facilities or Network Upgrades is to be borne by Transmission Owner, then Transmission Owner shall commence design of Transmission Owner’s Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Interim Availability Interconnection System Impact Study;

5.5.2 Transmission Owner has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones;

5.5.3 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.75 by the dates specified in Appendix B, Milestones; and

5.5.4 The Parties have executed this Interim GIA.

5.6 **Construction Commencement.** Transmission Owner shall commence construction of Transmission Owner’s Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Owner’s Interconnection Facilities and Network Upgrades;

5.6.3 Transmission Owner has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.6.4 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.75.

5.7 **Work Progress.** The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Parties may, at any time, request a progress report from other Parties. If, at any time, Interconnection
Customer determines that the completion of Transmission Owner’s Interconnection Facilities and Network Upgrades will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider and Transmission Owner of such later date upon which the completion of Transmission Owner’s Interconnection Facilities and Network Upgrades will be required.

5.8 **Information Exchange.** As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with the Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 **Reserved.**

5.10 **Interconnection Customer's Interconnection Facilities ("ICIF").** Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.10.1 **Interconnection Customer's Interconnection Facility Specifications.** Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Owner at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date, and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Owner shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 **Transmission Owner’s Review.** Transmission Owner’s review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Owner, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner.

5.10.3 **ICIF Construction.** The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional
diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Generating Facility. The Interconnection Customer shall provide Transmission Owner specifications for the excitation system, automatic voltage regulator, Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.10.4 **Updated Information Submission by Interconnection Customer.** The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date. Interconnection Customer shall submit a completed copy of the Generating Facility data requirements contained in Appendix 1 to the GIP. It shall also include any additional information provided to Transmission Provider for the Interconnection Feasibility and Interconnection Facilities Studies. Information in this submission shall be the most current Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreements between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on the Transmission System based on the actual data submitted pursuant to this Article 5.10.4. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

5.10.5 **Information Supplementation.** Prior to the Commercial Operation Date, or as soon as possible thereafter, the Parties shall supplement their information submissions described above in this Article 5 with any and all “as-built” Generating Facility information or “as-tested” performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Generating Facility as required by Good Utility Practice such as an open circuit “step voltage” test on the Generating Facility to verify proper operation of the Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent (5 percent) change in Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Generating Facility terminal and field voltages. In the event that
direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Generating Facility’s terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Generating Facility terminal or field voltages is provided. Generating Facility testing shall be conducted and results provided to the Transmission Provider for each individual generating unit in a station.

Subsequent to the Commercial Operation Date, the Interconnection Customer shall provide Transmission Owner and Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Owner shall provide the Interconnection Customer and Transmission Provider any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Owner-owned substation that may affect the Interconnection Customer’s Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

5.11 Transmission Owner’s Interconnection Facilities Construction. Transmission Owner’s Interconnection Facilities and Network Upgrades shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Owner shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Owner’s Interconnection Facilities and Network Upgrades [include appropriate drawings and relay diagrams].

Transmission Owner will obtain control of Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to any other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Generating Facility with the Transmission System; (ii) operate and maintain the Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this Interim GIA pursuant to Article 2.5. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other
than Interconnection Customer or Transmission Owner, Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 Permits. Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. Interconnection Customer may request Transmission Owner to construct, and Transmission Owner shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Reserved.

5.17 Taxes.

5.17.1 Interconnection Customer Payments Not Taxable. The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Owner for the installation of Transmission Owner's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations and Covenants. In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Owner for Transmission Owner's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of Transmission Owner's Interconnection
Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Transmission Owner's request, Interconnection Customer shall provide Transmission Owner with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Owner represents and covenants that the cost of Transmission Owner's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Owner. Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Transmission Owner from the cost consequences of any current tax liability imposed against Transmission Owner as the result of payments or property transfers made by Interconnection Customer to Transmission Owner under this Interim GIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Owner.

Transmission Owner shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this Interim GIA unless (i) Transmission Owner has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Owner should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Owner to report payments or property as income subject to taxation; provided, however, that Transmission Owner may require Interconnection Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to Transmission Owner (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Owner for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Owner of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission Owner upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.
5.17.4 Tax Gross-Up Amount. Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the Parties, this means that Interconnection Customer will pay Transmission Owner, in addition to the amount paid for the Interconnection Facilities, and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Owner ("Current Taxes") on the excess of (a) the gross income realized by Transmission Owner as a result of payments or property transfers made by Interconnection Customer to Transmission Owner under this Interim GIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Owner to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Owner’s composite federal and state tax rates at the time the payments or property transfers are received and Transmission Owner will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Transmission Owner’s anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Owner’s current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1 -Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 Private Letter Ruling or Change or Clarification of Law. At Interconnection Customer's request and expense, Transmission Owner shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission Owner under this Interim GIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Owner and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Owner shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Owner shall allow
Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 Subsequent Taxable Events. If, within 10 years from the date on which the relevant Transmission Owner’s Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this Interim GIA terminates and Transmission Owner retains ownership of the Interconnection Facilities and Network Upgrades, Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Owner, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 Contests. In the event any Governmental Authority determines that Transmission Owner’s receipt of payments or property constitutes income that is subject to taxation, Transmission Owner shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Owner may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Owner may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Owner reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Owner shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Owner on a periodic basis, as invoiced by Transmission Owner, Transmission Owner’s documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Owner may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Owner, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's
consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Owner for the tax at issue in the contest.

5.17.8 Refund. In the event that (a) a private letter ruling is issued to Transmission Owner which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Owner under the terms of this Interim GIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Owner in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Owner under the terms of this Interim GIA is not taxable to Transmission Owner, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Owner are not subject to federal income tax, or (d) if Transmission Owner receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Owner pursuant to this Interim GIA, Transmission Owner shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amount paid by Interconnection Customer to Transmission Owner for such taxes which Transmission Owner did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Owner refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Owner, any refund or credit Transmission Owner receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Owner for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Owner to any Governmental Authority resulting from an offset or credit); provided, however, that Transmission Owner will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Owner has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to Transmission Owner’s Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.
5.17.9 **Taxes Other Than Income Taxes.** Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Owner may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Owner for which Interconnection Customer may be required to reimburse Transmission Owner under the terms of this Interim GIA. Interconnection Customer shall pay to Transmission Owner on a periodic basis, as invoiced by Transmission Owner, Transmission Owner’s documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Owner for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Owner.

5.18 **Tax Status.** All Parties shall cooperate with each other to maintain their tax status. Nothing in this Interim GIA is intended to adversely affect any Party’s tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

5.19 **Modification.**

5.19.1 **General.** Each Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect another Party's facilities, that Party shall provide to the other Parties sufficient information regarding such modification so that the other Parties may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Parties at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Owner shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Owner’s Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.
5.19.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this Interim GIA and Good Utility Practice.

5.19.3 Modification Costs. Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Owner makes to Transmission Owner’s Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Owner’s Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

5.20 Delays. If a Network Upgrade(s) identified in Appendix A is delayed during the construction process and the Commercial Operation Date for the Generating Facility identified in Appendix B is no longer feasible, the Commercial Operation Date in Appendix B may be modified to no later than six (6) months following the in-service date for the last Network Upgrade identified in Appendix A.

Article 6. Testing and Inspection

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, Transmission Owner shall test Transmission Owner’s Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 Right to Observe Testing. Each Party shall notify the other Parties in advance of its performance of tests of its Interconnection Facilities. The other Parties have the right, at its own expense, to observe such testing.
6.4 **Right to Inspect.** Each Party shall have the right, but shall have no obligation to: (i) observe another Parties’ tests and/or inspection of any of its System Protection Facilities and other protective equipment, including power system stabilizers; (ii) review the settings of the other Parties’ System Protection Facilities and other protective equipment; and (iii) review another Parties’ maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. Any Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Parties. The exercise or non-exercise by another Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that any Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this Interim GIA.

Article 7. **Metering**

7.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Owner shall install Metering Equipment at the Point of Interconnection prior to any operation of the Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Generating Facility shall be measured at or, at Transmission Owner’s option, compensated to, the Point of Interconnection. Transmission Owner shall provide metering quantities, in analog and/or digital form, to Interconnection Customer and Transmission Provider on a same-time basis using communication as provided in Article 8. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 **Check Meters.** Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Owner’s meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this Interim GIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Owner or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 **Standards.** Transmission Owner shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

7.4 **Testing of Metering Equipment.** Transmission Owner shall inspect and test all Transmission Owner-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Owner shall, at Interconnection Customer’s expense, inspect or test Metering Equipment more frequently than every two (2) years. Transmission Owner shall give reasonable notice of the time when any inspection or test shall take place, and
Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Owner’s failure to maintain, then Transmission Owner shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Owner shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 Metering Data. At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Owner and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Generating Facility to the Point of Interconnection.

Article 8. Communications

8.1 Interconnection Customer Obligations. Interconnection Customer shall maintain satisfactory operating communications with Transmission Owner’s Transmission System dispatcher or representative designated by Transmission Owner. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Owner as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Generating Facility to the location(s) specified by Transmission Owner. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 Remote Terminal Unit. Prior to the Initial Synchronization Date of the Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Owner at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Owner through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Owner. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Owner.
Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 **No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

Article 9. **Operations**

9.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Parties all information that may reasonably be required by the other Parties to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 **Control Area Notification.** At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider and Transmission Owner in writing of the Control Area in which the Generating Facility will be located. If Interconnection Customer elects to locate the Generating Facility in a Control Area other than the Control Area in which the Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this Interim GIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Generating Facility in the other Control Area.

9.3 **Transmission Provider and Transmission Owner Obligations.** Transmission Provider and Transmission Owner shall cause the Transmission System and Transmission Owner’s Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this Interim GIA. Transmission Provider or Transmission Owner may provide operating instructions to Interconnection Customer consistent with this Interim GIA and Transmission Owner’s operating protocols and procedures as they may change from time to time. Transmission Provider and Transmission Owner will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 **Interconnection Customer Obligations.** Interconnection Customer shall at its own expense operate, maintain and control the Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this Interim GIA. Interconnection Customer shall operate the Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this Interim GIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they...
may change from time to time. Any Party may request that another Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this Interim GIA.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, the Interconnection Customer is responsible for the proper synchronization of the Generating Facility to the Transmission System.

9.6 Reactive Power.

9.6.1 Power Factor Design Criteria. Interconnection Customer shall design the Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider or Transmission Owner has established different requirements that apply to all generators in the Control Area on a comparable basis. A wind generator plant shall maintain a power factor within the range of .95 leading to .95 lagging, measured at the Point of Interconnection as defined in this Interim GIA, if the Transmission Provider’s Interconnection Study shows that such a requirement is necessary to ensure safety or reliability.

9.6.2 Voltage Schedules. Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Transmission Provider and/or Transmission Owner shall require Interconnection Customer to operate the Generating Facility to produce or absorb reactive power within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Owner’s voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Owner shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the Transmission Owner.

9.6.2.1 Governors and Regulators. Whenever the Generating Facility is operated in parallel with the Transmission System and the speed governors (if installed on the generating unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, Interconnection Customer shall operate the Generating Facility with its speed governors and voltage regulators in automatic operation. If the Generating Facility's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify Transmission Owner’s system operator, or its designated representative, and ensure that such Generating Facility's reactive power production or
absorption (measured in Mvars) are within the design capability of the Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Generating Facility for an under or over frequency condition in accordance with Good Utility Practice and Applicable Reliability Standards.

9.6.3 Payment for Reactive Power. Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Generating Facility when Transmission Owner requests Interconnection Customer to operate its Generating Facility outside the range specified in Article 9.6.1. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed; provided however, to the extent the Tariff contains a provision providing for such compensation, that Tariff provision shall control.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to all Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Parties of such removal.

9.7.1.2 Outage Schedules. Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection
Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 Outage Restoration. If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects another Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Parties, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 Interruption of Service. In addition to any reduction in Interconnection Service required pursuant to Article 4.2.2, if required by Good Utility Practice to do so, Transmission Provider and/or Transmission Owner may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's and/or Transmission Owner’s ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider or Transmission Owner shall coordinate
with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Owner; and

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 Under-Frequency and Over Frequency Conditions. The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a generating facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 System Protection Facilities. Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Owner shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Owner’s Interconnection Facilities or the Transmission System as a result of the interconnection of the Generating Facility and the Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing
unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 Requirements for Protection. In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Owner’s equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Generating Facility.

9.7.6 Power Quality. No Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.8 Switching and Tagging Rules. Each Party shall provide the other Parties a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.
9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Owner’s Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Generating Facility or the Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

Article 10. Maintenance

10.1 Transmission Owner Obligations. Transmission Owner shall maintain the Transmission System and Transmission Owner’s Interconnection Facilities in a safe and reliable manner and in accordance with this Interim GIA.

10.2 Interconnection Customer Obligations. Interconnection Customer shall maintain the Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this Interim GIA.

10.3 Coordination. The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Generating Facility and the Interconnection Facilities.

10.4 Secondary Systems. Each Party shall cooperate with the others in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or
DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact another Party. Each Party shall provide advance notice to the other Parties before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer’s Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Owner’s Interconnection Facilities.

Article 11. Performance Obligation

11.1 Interconnection Customer Interconnection Facilities. Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer’s Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 Reserved.

11.3 Transmission Owner’s Interconnection Facilities. Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Owner’s Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

11.4 Network Upgrades and Distribution Upgrades. All Network Upgrades and Distribution Upgrades described in Appendix A shall be constructed in accordance with the process set forth in Section VI of Attachment O. Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades that are associated with that Transmission Owner’s system. The Distribution Upgrades and Network Upgrades described in Appendix A shall be solely funded by Interconnection Customer unless Transmission Owner elects to fund the capital for the Distribution Upgrades or Network Upgrades.

11.45 Transmission Credits.

11.54.1 Credits for Amounts Advanced for Network Upgrades. Interconnection Customer shall be entitled to credits in accordance with Attachment Z2 of the Tariff for any Network Upgrades including any tax gross-up...
or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection Customer pursuant to Article 5.17.8.

11.45.2 Special Provisions for Affected Systems. Unless Transmission Provider provides, under the Interim GIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

11.45.3 Notwithstanding any other provision of this Interim GIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain transmission credits for transmission service that is not associated with the Generating Facility.

11.6 Initial Payment.

Interconnection Customer shall make an initial payment (“Initial Payment”) equal to the greater of a) twenty (20) percent of the total cost of Network Upgrades, Shared Network Upgrades, Transmission Owner Interconnection Facilities and/or Distribution Upgrades listed in Appendix A or b) $4,000/MW of the size of the Generating Facility. Any remaining milestone deposits provided in Section 8.2 and Section 8.9 of the GIP will be applied to this requirement. The Initial Payment shall be provided to Transmission Owner or Transmission Provider as required in Appendix B by Interconnection Customer pursuant to this Article 11.6 within the later of a) thirty (30) days of the execution of the GIA by all Parties, or b) thirty (30) days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by Interconnection Customer, or c) thirty (30) days of the filing if the GIA is filed unexecuted and the Initial Payment is not being protested by Interconnection Customer. The Interconnection Customer may agree to make this Initial Payment non-refundable in accordance with Article 11.6.2. If this GIA is terminated, then the Initial Payment shall be refunded to the Interconnection Customer less:

a. any costs that have been incurred for the construction of the facilities specified in Appendix A;

b. any funds that have been committed for the construction of those Shared Network Upgrades, or Network Upgrades, assigned to another interconnection customer where such upgrade costs would not have been assigned but for the termination of the GIA; or

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c. any costs that have been incurred for the construction of those Shared Network Upgrades, or Network Upgrades, that were paid for by another interconnection customer that are now unnecessary due to the termination of the GIA.

11.6.1 If the Interconnection Customer has stated its intent to use the existing interconnection capacity of the Transmission System in order to achieve its Commercial Operation Date, the Interconnection Customer will provide the greater of a) one hundred (100) percent of the total cost of Network Upgrades, Shared Network Upgrades, Transmission Owner Interconnection Facilities and/or Distribution Upgrades listed in Appendix A or b) $4,000/MW of the size of the Generating Facility. The milestone deposits provided in Section 8.2 and Section 8.9 of the GIP may suffice for this requirement. The initial payment shall be provided to Transmission Owner or Transmission Provider as required in Appendix B by Interconnection Customer pursuant to this Article 11.6 within the later of a) thirty (30) days of the execution of the GIA by all Parties, or b) thirty (30) days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by Interconnection Customer, or c) thirty (30) days of the filing if the GIA is filed unexecuted and the initial payment is not being protested by Interconnection Customer. This payment is not refundable upon termination of the GIA unless the higher queued interconnection customer chooses to retain its Network Upgrades by agreeing to make its Article 11.6 payment non-refundable in accordance with Article 11.6.2. These funds will be used first to pay for additional Network Upgrades cost assigned to other interconnection customers due to the Interconnection Customer stating its intent to use existing interconnection capacity. Any remaining funds will be applied to the Network Upgrades assigned to the Interconnection Customer.

11.6.2 If another interconnection customer has notified the Transmission Provider in writing of its intent to use the existing interconnection capacity of the Transmission System in accordance to Article 11.6.1 of its GIA, the Interconnection Customer shall be subject to a restudy in accordance with Article 11.4.2(d) to determine the new scope of Network Upgrades unless the Interconnection Customer notifies the Transmission Provider within 30 Calendar Days of the notice from Transmission Provider of its intent to retain the Network Upgrades listed in Appendix A agrees to make its Initial Payment in Article 11.6 non-refundable and authorizes engineering, procurement, and construction of those Network Upgrades in accordance with Article 5.5 and Article 5.6. Upon receipt of this authorization, the applicable dates in Appendix B shall be revised by the Parties. The Interconnection Customer continues to be subject to restudy conditions in Article 11.4.2(a-c).
11.75 Provision of Security.

11.75.1 Initial Security. Within fifteen (15) Business Days of the date that Interconnection Customer delivers to Transmission Provider an executed Interim GIA, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1 in the amount set forth in Appendix A to this Interim GIA. This amount represents either (a) the sum of the estimated costs for which Interconnection Customer will be responsible for the construction, procurement, and installation of the applicable portion of Transmission Owner’s Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which it will share cost responsibility as determined in the study designated in Appendix A.4. and 100 percent of the costs of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which Interconnection Customer has sole cost responsibility or (b) if the estimated costs above have not been established at the time Interconnection Customer requests Interim Interconnection Service, the initial security amount will be established by the Transmission Provider based on one or more completed studies for comparable interconnection requests.

11.57.2 Security Adjustment. In the event that the results of any subsequently posted study (e.g., Definitive Interconnection System Impact Study, Interconnection Facilities Study, or any other study required pursuant to the GIP in connection with Interconnection Service under this Interim GIA) indicates that Interconnection Customer’s cost responsibility for Interconnection Facilities, Network Upgrades, or Distribution Upgrades required to interconnect its Generating Facility is less than or greater than the amount set forth in Appendix A, the amount of security required under this Interim GIA shall be adjusted to reflect the Interconnection Customer’s revised amount of cost responsibility determined in such posted study. Transmission Provider shall notify Interconnection Customer of the revised security amount when it posts the study. If the security amount increases, Interconnection Customer shall provide the additional amount of security within fifteen (15) Business Days of receipt of such notification. If the security amount decreases, Transmission Provider and Interconnection Customer shall take the appropriate action to reduce the amount of security held by Transmission Provider within fifteen (15) Business Days of Interconnection Customer’s receipt of such notification. If Interconnection Customer fails to provide additional security as prescribed in this Article 11.5.2, this Interim GIA will be terminated in accordance with Article 2.3.

In addition:

11.75.2.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.
11.75.2.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.75.2.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.68 Interconnection Customer Compensation. If Transmission Provider or Transmission Owner requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this Interim GIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to the Tariff. Interconnection Customer shall serve Transmission Provider with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this Interim GIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

11.86.1 Interconnection Customer Compensation for Actions During Emergency Condition. Transmission Provider shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.68.

Article 12. Invoice

The terms of this Article 12 apply to billing between the Parties for construction and operation and maintenance charges. All other billing will be handled according to the Tariff.

12.1 General. Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this Interim GIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice. Within six months after completion of the construction of Interconnection Facilities and the Network Upgrades to be constructed pursuant to this Interim GIA, the Interconnection Customer shall receive an invoice of the final cost due under this Interim
GIA, including any applicable cost due to termination, which shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Interconnection Customer shall receive a refund of any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this Interim GIA.

12.4 Disputes. In the event of a billing dispute between the Parties, Transmission Owner, and Transmission Provider shall continue to provide Interconnection Service under this Interim GIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Owner or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Owner may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

Article 13. Emergencies

13.1 Definition. “Emergency Condition” shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, or the electric systems of others to which the Transmission Provider’s Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, Transmission Owner’s Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Interim Generator Interconnection Agreement, to possess black start capability.

13.2 Obligations. Each Party shall comply with the Emergency Condition procedures of NERC, the Applicable Reliability Council, Transmission Provider, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.
13.3 Notice. Transmission Provider or Transmission Owner shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Owner’s Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Generating Facility or Interconnection Customer's Interconnection Facilities.

Interconnection Customer shall notify Transmission Provider and Transmission Owner promptly when it becomes aware of an Emergency Condition that affects the Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Owner’s Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Owner’s facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

13.4 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Owner, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or Transmission Owner or otherwise regarding the Transmission System.

13.5 Transmission Provider and Transmission Owner Authority.

13.5.1 General. Transmission Provider and/or Transmission Owner may take whatever actions or inactions with regard to the Transmission System or Transmission Owner’s Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Owner’s Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider and Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider and/or Transmission Owner may, on the basis of technical considerations, require the Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with black start (if available) or restoration efforts; or altering the outage schedules of the Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's and Transmission Owner's operating instructions concerning Generating Facility real power and reactive power output.
power output within the manufacturer's design limitations of the Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 Reduction and Disconnection. Transmission Provider and/or Transmission Owner may reduce Interconnection Service or disconnect the Generating Facility or Interconnection Customer's Interconnection Facilities, when such reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment, reduction, or disconnection of Transmission Provider pursuant to Transmission Provider's Tariff or Articles 2.5, 4.2.2 and 9.7.2. When Transmission Provider and/or Transmission Owner can schedule the reduction or disconnection in advance, Transmission Provider and/or Transmission Owner shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider and/or Transmission Owner shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer, Transmission Provider and/or Transmission Owner. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.6 Interconnection Customer Authority. Consistent with Good Utility Practice and this Interim GIA and the GIP, Interconnection Customer may take actions or inactions with regard to the Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Owner’s Interconnection Facilities. Transmission Provider and/or Transmission Owner shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 Limited Liability. Except as otherwise provided in Article 11.6.1 of this Interim GIA, no Party shall be liable to the other Parties for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

Article 14. Regulatory Requirements and Governing Law

14.1 Regulatory Requirements. Each Party's obligations under this Interim GIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall
in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this Interim GIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act the Public Utility Holding Company Act of 2005, or the Public Utility Regulatory Policies Act of 1978, as amended by the 2005 Energy Policy Act.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this Interim GIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This Interim GIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

Article 15. Notices

15.1 General. Unless otherwise provided in this Interim GIA, any notice, demand or request required or permitted to be given by any Party to another and any instrument required or permitted to be tendered or delivered by any Party in writing to another shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Any Party may change the notice information in this Interim GIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by any Party to another and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Parties in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

Article 16. Force Majeure

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.
16.1.2 No Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Parties in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

Article 17. Default

17.1 Default.

17.1.1 General. No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this Interim GIA or the result of an act or omission of another Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Right to Terminate. If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this Interim GIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Interim GIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Interim GIA.

Article 18. Indemnity, Consequential Damages and Insurance

18.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties,
arising out of or resulting from the other Parties’ action or inactions of its obligations under this Interim GIA on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

18.1.1 Indemnified Person. If an indemnified person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 Indemnifying Party. If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 18, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

18.1.3 Indemnity Procedures. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any
action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

18.2 **Consequential Damages.** Other than the Liquidated Damages heretofore described, in no event shall any Party be liable to any other Party under any provision of this Interim GIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which any Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 **Insurance.** Interconnection Customer and Transmission Owner shall at their own expense, maintain in force throughout the period of this Interim GIA, and until released by all other Parties, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located. The minimum limits for the Employers Liability insurance shall be One Million Dollars ($1,000,000) each accident bodily injury by accident, One Million Dollars ($1,000,000) each employee bodily injury by disease, and One Million Dollars ($1,000,000) policy limit bodily injury by disease.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards (if applicable), independent contractors coverage, coverage for pollution (if exposure is present) and punitive or exemplary damages, with minimum limits of One Million Dollars ($1,000,000) each occurrence/Two Million Dollars ($2,000,000) general aggregate and Two Million Dollars ($2,000,000) products and completed operations aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) each occurrence/Twenty Million Dollars ($20,000,000) general aggregate.
18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this Interim GIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this Interim GIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed to by all Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Interconnection Customer and Transmission Owner are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

18.3.9 Within ten (10) days following execution of this Interim GIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, Interconnection Customer and Transmission Owner shall provide certification of all insurance required in this Interim GIA, executed by each insurer or by an authorized representative of each insurer to the Other Party Group.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements...
to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this Interim GIA.

Article 19  Assignment.

19.1 Assignment. This Interim GIA may be assigned by any Party only with the written consent of the other Parties; provided that any Party may assign this Interim GIA without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Interim GIA; and provided further that Interconnection Customer shall have the right to assign this Interim GIA, without the consent of Transmission Provider or Transmission Owner, for collateral security purposes to aid in providing financing for the Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider and Transmission Owner of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider and Transmission Owner of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.57 and 18.3. Any assignment under this article not solely for collateral security purposes shall be conditioned on the simultaneous assignment of Interconnection Customer's Queue Position to assignee and assignee demonstrating the ability to enter into and fulfill the obligations of a final GIA. Any attempted assignment that violates this article is void and ineffective. Any assignment under this Interim GIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

Article 20. Severability

20.1 Severability. If any provision in this Interim GIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Interim GIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Owner) seeks and obtains such a final determination with respect to any provision of the Negotiated Option (Article 5.1.3), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

Article 21. Comparability
21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

Article 22. Confidentiality

22.1 Confidentiality. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to another prior to the execution of this Interim GIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by any Party, a Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term. During the term of this Interim GIA, and for a period of three (3) years after the expiration or termination of this Interim GIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this Interim GIA; or (6) is required, in accordance with Article 22.1.7 of the Interim GIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Interim GIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 Release of Confidential Information. No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants,
or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this Interim GIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 Rights. Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses another other Party. The disclosure by any Party to another Party of Confidential Information shall not be deemed a waiver by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 No Warranties. By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to another Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to another Party under this Interim GIA or its regulatory requirements.

22.1.7 Order of Disclosure. If a court or a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires a Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of this Interim GIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 Termination of Agreement. Upon termination of this Interim GIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.
22.1.9 Remedies. In the instance where Transmission Owner is a Federal Power Agency, as specified in the opening paragraph of this Agreement, then this section 22.1.9 shall not apply to Transmission Owner. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 Disclosure to FERC, its Staff, or a State. Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 C.F.R. Section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Interim GIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. Section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying another Party to this Interim GIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to the Interim GIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. Section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this Interim GIA ("Confidential Information") shall not be disclosed by another Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this Interim GIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization.
The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

22.1.12 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

Article 23. Environmental Releases

23.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

Article 24. Information Requirements

24.1 Information Acquisition. Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 Information Submission by Transmission Provider. The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

Article 25. Information Access and Audit Rights

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Parties information that is in the possession of the disclosing Party and is necessary
in order for the other Parties to: (i) verify the costs incurred by the disclosing Party for which the other Parties are responsible under this Interim GIA; and (ii) carry out its obligations and responsibilities under this Interim GIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this Interim GIA.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Parties when the notifying Party becomes aware of its inability to comply with the provisions of this Interim GIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Parties receiving such notification to allege a cause for anticipatory breach of this Interim GIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this Interim GIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to another Party, to audit at its own expense that other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this Interim GIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this Interim GIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Transmission Owner’s Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Owner's issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to any Party's performance or satisfaction of all obligations under this Interim GIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.
25.5 **Audit Results.** If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

**Article 26. Subcontractors**

26.1 **General.** Nothing in this Interim GIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Interim GIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Interim GIA in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

26.2 **Responsibility of Principal.** The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Interim GIA. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Owner be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this Interim GIA. Any applicable obligation imposed by this Interim GIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 **No Limitation by Insurance.** The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

**Article 27. Disputes**

27.1 **Submission.** In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with this Interim GIA or its performance, the Parties agree to resolve such dispute using the dispute resolution procedures of the Tariff.

**Article 28. Representations, Warranties, and Covenants**

28.1 **General.** Each Party makes the following representations, warranties and covenants:

28.1.1 **Good Standing.** Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Interim GIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Interim GIA.
28.1.2 Authority. Such Party has the right, power and authority to enter into this Interim GIA, to become a Party hereto and to perform its obligations hereunder. This Interim GIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 No Conflict. The execution, delivery and performance of this Interim GIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this Interim GIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Interim GIA, and it will provide to any Governmental Authority notice of any actions under this Interim GIA that are required by Applicable Laws and Regulations.

Article 29. Joint Operating Committee

29.1 Joint Operating Committee. At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer, Transmission Owner and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Party shall notify the other Parties of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of any Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this Interim GIA. All Parties shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

29.1.1 Establish data requirements and operating record requirements.

29.1.2 Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

29.1.3 Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Owner’s and Interconnection Customer's facilities at the Point of Interconnection.
29.1.4 Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Generating Facility and other facilities that impact the normal operation of the interconnection of the Generating Facility to the Transmission System.

29.1.5 Ensure that information is being provided by each Party regarding equipment availability.

29.1.6 Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

Article 30. Miscellaneous

30.1 Binding Effect. This Interim GIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this Interim GIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Interim GIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. This Interim GIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Interim GIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Interim GIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this Interim GIA or such Appendix to this Interim GIA, or such Section to the GIP or such Appendix to the GIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Interim GIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 Entire Agreement. This Interim GIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, among the Parties with respect to the subject matter of this Interim GIA. There are no other agreements, representations, warranties, or covenants
which constitute any part of the consideration for, or any condition to, a Party's compliance with its obligations under this Interim GIA.

30.5 **No Third Party Beneficiaries.** This Interim GIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 **Waiver.** The failure of a Party to this Interim GIA to insist, on any occasion, upon strict performance of any provision of this Interim GIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by a Party of its rights with respect to this Interim GIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Interim GIA. Termination or Default of this Interim GIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Interim GIA shall, if requested, be provided in writing.

30.7 **Headings.** The descriptive headings of the various Articles of this Interim GIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Interim GIA.

30.8 **Multiple Counterparts.** This Interim GIA may be executed in three or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 **Amendment.** The Parties may by mutual agreement amend this Interim GIA by a written instrument duly executed by each of the Parties.

30.10 **Modification by the Parties.** The Parties may by mutual agreement amend the Appendices to this Interim GIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Interim GIA upon satisfaction of all Applicable Laws and Regulations.

30.11 **Reservation of Rights.** Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Interim GIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under Sections 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Interim GIA pursuant to Sections 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Interim GIA shall limit the rights of the Parties or of FERC under Sections 205 or 206 of the Federal Power Act and FERC's
rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 **No Partnership.** This Interim GIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.
IN WITNESS WHEREOF, the Parties have executed this Interim GIA in triplicate originals, each of which shall constitute and be an original effective Agreement among the Parties.

SOUTHWEST POWER POOL, INC.

By: ________________________
Title: ________________________
Date: ________________________

[Insert name of Transmission Owner]

By: ________________________
Title: ________________________
Date: ________________________

[Insert name of Interconnection Customer]

By: ________________________
Title: ________________________
Date: ________________________
Appendix A to Interim GIA

Interconnection Facilities, Network Upgrades, Distribution Upgrades, Security, Type and Amount of Interconnection Service, Construction Option, and Higher Queued Project List

1. Interconnection Facilities: [include description, responsible party, and estimated costs]
   A. Interconnection Customer’s Interconnection Facilities
   B. Transmission Owner Interconnection Facilities

2. Network Upgrades: [include description, responsible party, and estimated costs]
   A. Stand Alone Network Upgrades
   B. Network Upgrades For Which Interconnection Customer Is Solely Responsible
   C. Network Upgrades For Which Interconnection Customer Shares Cost Responsibility

3. Distribution Upgrades: [include description, responsible party, and estimated costs]

4. Security, Credits and Taxes:
   A. The amount of initial security to be provided by Interconnection Customer in accordance with Article 11.5.1 is $__________. The required amount of security required pursuant to this Interim GIA may be adjusted pursuant to Article 11.5.2 of this Agreement.
   B. The estimated portion of the Network Upgrades identified in Section 2 of this Appendix A that could be subject to the credits described in Article 11.4 of this Agreement is $__________
   C. Interconnection Customer’s estimated liability for reimbursement of Transmission Owner for taxes, interest and/or penalties under Article 5.17.3 of this Agreement is $__________

5. Type and Amount of Interim Interconnection Service:
The type of Interim Interconnection Service to be provided pursuant to this Interim GIA shall be [Energy Resource or Network Resource] Interim Interconnection Service in the amount of ______ MW.

6. **Construction Option For Stand Alone Upgrades and Transmission Owner Interconnection Facilities:**

The Parties have agreed to the construction options for the Stand Alone Network Upgrades and Transmission Owner Interconnection Facilities as specified below:

A. **Stand Alone Network Upgrades:**

[List the Stand Alone Network Upgrade and the construction option]

B. **Transmission Owner Interconnection Facilities:**

[List the Transmission Owner Interconnection Facility and the option]

7. **Higher Queued Projects:**

[list Higher Queued Projects]

8. **Permits, Licenses and Authorizations:**

9. **Penalty, Redispatch or Market-Related Costs:**

10. **One-Line Diagram:**
Appendix B to Interim GIA

Milestones
Appendix C to Interim GIA

Interconnection Details

This Appendix C is an integral part of this Interim GIA.

1. Description of Generating Facility:

2. Description of Point of Change of Ownership:

3. Description of Point of Interconnection:

4. Interconnection Guidelines:
The unique requirements of each generation interconnection will dictate the establishment of mutually agreeable Interconnection Guidelines that further define the requirements of this Agreement. The Interconnection Guidelines will address, but not be limited to, the following:
Appendix D to Interim GIA

Infrastructure and Operational Security Arrangements

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.
Appendix E to Interim GIA

Commercial Operation Date

[Date]

____________________, __________________________
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR  72223-4936

[Transmission Owner Address]

Re: ___________________________________

Dear ___________________: 

On [Date], _________________ has completed Trial Operation of referenced generation facility in the Interim Generation Interconnection Agreement dated _____________________. This letter confirms that _________________ commenced Commercial Operation of the referenced generation facility, effective as of [Date plus one day].

Thank you.

[Signature]

[Interconnection Customer Representative]
Appendix F to Interim GIA

ADDRESSES FOR DELIVERY OF NOTICES AND BILLINGS

Notices:

Transmission Provider:

___________________________, ______________________________
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR  72223-4936

Transmission Owner:

[To be Supplied]

Interconnection Customer:

[To be Supplied]

Billings and Payments: [Specify addresses for construction invoices, O&M invoices and settlement of ancillary services]

Transmission Provider:

___________________________, ______________________________
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR  72223-4936

Transmission Owner:

[To be Supplied]

Interconnection Customer:

[To be Supplied]
Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

______________________________, __________________________
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR  72223-4936
Phone: __________________________
Facsimile: 501-482-2022

Transmission Owner:

[TO BE SUPPLIED]

Interconnection Customer:

[TO BE SUPPLIED]

Operational Communications: [Identify contacts for operations]

Transmission Provider:

_______________________________, _________________________
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR  72223-4936
Phone: __________________________
Facsimile: 501-482-2022

Transmission Owner:

[TO BE SUPPLIED]

Interconnection Customer:

[TO BE SUPPLIED]
Appendix G to Interim GIA

REQUIREMENTS OF GENERATORS RELYING ON NEWER TECHNOLOGIES

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this Interim GIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or “GSU”), after which, if the fault remains following the location-specific normal clearing
time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

   ii. Power Factor Design Criteria (Reactive Power)

   A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this Interim GIA, if the Transmission Provider’s System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

   iii. Supervisory Control and Data Acquisition (SCADA) Capability

   The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location,
and importance in maintaining generation resource adequacy and transmission system reliability in its area.
CERTIFICATION CODES AND STANDARDS

Certification and interconnection of Interconnection Customer’s facilities with Transmission Owner’s facilities shall be governed by all applicable local, state and federal statutes. In addition, Interconnection Customer’s facilities shall be installed in accordance with all provisions set forth in Transmission Owner’s Facility Connection Standard, Transmission Owner Service Standard and the National Electrical Safety Code (ANSIC2), National Electrical Code (NFPA70), North American Electric Reliability Council (NERC), Regional Reliability Councils, American National Standards Institute (ANSI), Institute of Electrical and Electronics Engineers (IEEE), or other regulatory or governing body having jurisdiction. Connection of Interconnection Customer’s facilities with Transmission Owner’s facilities shall further be governed by any applicable statute, rule, order, provision, guide, or code of an organization, council, institute, regulatory or governing body having jurisdiction over such matters.

A sample list of such requirements is shown below (Note this list is not all-inclusive and the entities responsible for these requirements may update them at any time. The current versions shall be applicable.):

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code


IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms
NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1
APPENDIX 10 TO GIP

CERTIFICATION OF SMALL GENERATOR EQUIPMENT PACKAGES

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in GIP Appendix 9, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer’s literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the Parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 Any equipment package approved and listed in a state by that state’s regulatory body for interconnected operation in that state prior to the effective date of these GIP shall be considered certified under these procedures for use in that state.
APPENDIX 11 TO GIP

APPLICATION, PROCEDURES, AND TERMS AND CONDITIONS FOR INTERCONNECTING A CERTIFIED INVERTER-BASED SMALL GENERATING FACILITY NO LARGER THAN 10 KW ("10 KW INVERTER PROCESS")

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Transmission Provider.

2.0 The Transmission Provider acknowledges to the Customer receipt of the Application within three Business Days of receipt.

3.0 The Transmission Provider evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.

4.0 The Transmission Provider verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in Section 14 of the Generator Interconnection Procedures (GIP). The Transmission Provider has 15 Business Days to complete this process. Unless the Transmission Provider determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the Transmission Provider approves the Application and returns it to the Customer. Note to Customer: Please check with the Transmission Provider before submitting the Application if disconnection equipment is required.

5.0 After installation, the Customer returns the Certificate of Completion to the Transmission Provider and Transmission Owner. Prior to parallel operation, the Transmission Provider and Transmission Owner may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.

6.0 The Transmission Owner notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Transmission Owner
has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Transmission Owner is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Transmission Owner does not inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

7.0 Contact Information – The Customer must provide the contact information for the legal applicant (i.e., the Interconnection Customer). If another entity is responsible for interfacing with the Transmission Provider, that contact information must be provided on the Application.

8.0 Ownership Information – Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.

9.0 UL1741 Listed – This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.
This Application is considered complete when it provides all applicable and correct information required below. Documentation of Site Control must be submitted with the Interconnection Request. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of $500 must accompany this Application.

Interconnection Customer

Name: _______________________________________________________________________
Contact Person:_________________________________________________________________
Address: _______________________________________________________________________
City: ___________________________ State: __________________ Zip: ______________
Telephone (Day): ____________________ (Evening): ____________________________
Fax: ______________________________ E-Mail Address: _________________________

Contact (if different from Interconnection Customer)

Name: ______________________________________________________________________
Address: _____________________________________________________________________
City: ___________________________ State: __________________ Zip: ______________
Telephone (Day): ____________________ (Evening): ____________________________
Fax: ______________________________ E-Mail Address: _________________________

Owner of the facility (include % ownership by any electric utility): __________________________

Small Generating Facility Information

Location (if different from above): ____________________________
Electric Service Company: _______________________________________
Account Number: ________________________________________________
Inverter Manufacturer: ____________________________ Model ____________________________

Nameplate Rating: _____ (kW) _____ (kVA) _____ (AC Volts)

Single Phase _______ Three Phase _______

System Design Capacity: _________ (kW) _______ (kVA)

Prime Mover: Photovoltaic [ ] Reciprocating Engine [ ] Fuel Cell [ ]

Turbine [ ] Other _______________________________

Energy Source: Solar [ ] Wind [ ] Hydro [ ] Diesel [ ] Natural Gas [ ]

Fuel Oil [ ] Other (describe) _______________________________

Is the equipment UL1741 Listed? Yes No [ ]

If Yes, attach manufacturer’s cut-sheet showing UL1741 listing

Estimated Installation Date: _____________ Estimated In-Service Date: ____________

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Appendix 9 and 10 of the Generator Interconnection Procedures (GIP), or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

<table>
<thead>
<tr>
<th>Equipment Type</th>
<th>Certifying Entity</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td></td>
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<tr>
<td>2.</td>
<td></td>
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<tr>
<td>3.</td>
<td></td>
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<tr>
<td>4.</td>
<td></td>
</tr>
<tr>
<td>5.</td>
<td></td>
</tr>
</tbody>
</table>

**Interconnection Customer Signature**

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: ____________________________________________

Title: ____________________________ Date: ____________

________________________________________

**Contingent Approval to Interconnect the Small Generating Facility**

(For Transmission Provider use only)
Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Transmission Provider Signature: ________________________________________________

Title: ___________________________ Date: ____________

Application ID number: ______________

Transmission Provider waives inspection/witness test? Yes___No___

Transmission Owner Signature: ________________________________________________

Title: ___________________________ Date: ____________

Application ID number: ______________

Transmission Owner waives inspection/witness test? Yes___No___
Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes______ No ______

Interconnection Customer: _____________________________________________________________

Contact Person: _________________________________________________________________

Address: ________________________________________________________________

Location of the Small Generating Facility (if different from above):
___________________________________________________________________________________

City: _______________________________ State: ___________________ Zip Code: ______

Telephone (Day): ___________________________ (Evening): _____________________________

Fax: ________________________________ E-Mail Address: ______________________________

Electrician:
Name: ________________________________

Address: ________________________________________________________________

City: _______________________________ State: ___________________ Zip Code: ______

Telephone (Day): ___________________________ (Evening): _____________________________

Fax: ________________________________ E-Mail Address: ______________________________

License number: ________________________________

Date Approval to Install Facility granted by the Transmission Provider: ________________

Application ID number: ________________________________

Date Approval to Install Facility granted by the Transmission Owner: ________________

Inspection:
The Small Generating Facility has been installed and inspected in compliance with the local
building/electrical code of _______________________________________________________

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

______________________________________________________________________________

Print Name: ________________________________

Date: ___________

As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of
the signed electrical permit to (insert Transmission Provider information below):
Name: __________________, ______________________

Company: Southwest Power Pool, Inc.

Address: 201 Worthen Drive

City, State ZIP: Little Rock, AR 72223-4936

Fax: (501) 482-2022

Approval to Energize the Small Generating Facility (For Transmission Provider use only)

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Transmission Provider Signature: ______________________________

Title: _______________________________ Date: _____________
Terms and Conditions for Interconnecting an Inverter-Based 
Small Generating Facility No Larger than 10kW

1.0 Construction of the Facility

The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the Transmission Provider approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may operate Small Generating Facility and interconnect with the Transmission System or Distribution System once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Transmission Provider and Transmission Owner, and

2.3 The Transmission Owner has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Transmission Owner, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Transmission Owner shall provide a written statement to the Customer and the Transmission Provider that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or
2.3.2 If the Transmission Owner does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Transmission Owner waives the right to inspect the Small Generating Facility.

2.4 The Transmission Owner has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 Safe Operations and Maintenance

The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 Access

The Transmission Owner shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Transmission Owner shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 Disconnection

The Transmission Owner may temporarily disconnect the Small Generating Facility upon the following conditions:
5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.

5.4 The Transmission Owner shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 Indemnification

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Parties, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.0 Insurance

The Parties each agree to follow all applicable insurance requirements imposed by the state in which the Point of Interconnection is located. All insurance policies must be maintained with insurers authorized to do business in that state.

8.0 Limitation of Liability

Each Party’s liability to the other Parties for any loss, cost, claim, injury, liability, or expense, including reasonable attorney’s fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall a Party be liable to the other Parties for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.
9.0 **Termination**

The agreement to operate in parallel may be terminated under the following conditions:

9.1 **By the Customer**

By providing written notice to the Company.

9.2 **By the Company**

If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 **Permanent Disconnection**

In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

9.4 **Survival Rights**

This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 **Assignment/Transfer of Ownership of the Facility**

This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.

11.0 **No Applicability to Transmission Service.**
Nothing in this Agreement shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.
APPENDIX 12 TO GIP

CONSENT TO ASSIGNMENT OF GIA GEN-____-___ DATED __/__/____

To Whom It May Concern:

Southwest Power Pool, Inc. (“Transmission Provider”) and ____________ (“Transmission Owner”) have been asked to provide written consent to the assignment of that certain Generator Interconnection Agreement GEN-____-___ entered into on __/__/____ among Transmission Provider, ____________ (“Interconnection Customer”) and Transmission Owner (the “GIA”)*. Pursuant to Article 19.1 of the GIA, Interconnection Customer desires to assign GIA to ____________ (“Assignee”), and Assignee desires to assume the GIA.

Consistent with Article 19.1 of the GIA, Interconnection Customer represents to Transmission Provider and Transmission Owner that Assignee shall take assignment of the GIA and the related Interconnection Request number and queue position subject to the terms and conditions provided in the GIA, and the terms and conditions governing interconnection procedure and queue position contained in SPP’s Open Access Transmission Tariff (“OATT”), including but not limited to, all performance obligations, responsibilities and liabilities. Upon assignment of the GIA, Interconnection Customer will notify the Transmission Provider and Transmission Owner of the assignment. Further, to the knowledge of the undersigned representative of Interconnection Customer, after due inquiry, no default exists in the performance of Interconnection Customer’s obligations under the GIA.

Transmission Provider and Transmission Owner acknowledge that Interconnection Customer has the right to assign the GIA, either as a general assignment of the GIA or for purposes of obtaining financing, and does hereby expressly consent to such assignment. Interconnection Customer assigns the GIA and Assignee takes assignment subject to the provisions of Article 19.1 of the GIA. In granting consent, neither Transmission Provider nor Transmission Owner makes any other acknowledgments, representations or warranties of any kind.

This Consent to Assignment may be executed in one or more identical counterparts, including an electronic or facsimile copy hereof (and specifically including counterparts executed by the individual parties to indicate acknowledgement and agreement), each of which when executed by any one party and delivered to the Interconnection Customer shall be deemed an original and all of which taken together shall constitute a single instrument.

ACKNOWLEDGED AND AGREED

Southwest Power Pool, Inc. ____________________________ (Transmission Owner)

By: ____________________________
Name: ____________________________
Title: ____________________________
Date: ____________________________

__________________________ (Transmission Owner)

By: ____________________________
Name: ____________________________
Title: ____________________________
Date: ____________________________
___________________ (Interconnection Customer)

By: _____________________
Name: ___________________
Title: ____________________
Date: ____________________

* The agreement may have been executed under an older version of the pro forma OATT or for interim interconnection service; therefore it may be identified herein as a Large Generator Interconnection Agreement (“LGIA”) or an Interim Generator Interconnection Agreement (“Interim GIA”).

Proposed Market Protocols Language Revision (Redlined)

Proposed Business Practices Language Revision (Redlined)

Proposed Criteria Language Revision (Redlined)

Proposed Revisions to Other Corporate Documents (Redlined)
Cost Estimate Process Timeline

Legend
- SPP ITP Near-Term Task
- DTO ITP Near-Term Task
- SPP ITP10 Task
- DTO ITP10 Task
- SPP Ag Study Task
- SPP GI Study Task
- DTO Ag Study Task
- DTO GI Study Task

ITP Near-Term
- Model Development
- Solution Development
- Report Build
- Study Estimate Completion
- NPE Completion
- CPE Completion

ITP10
- Analysis & Project Screening
- Solution Finalization & Report Build
- Study Estimate Completion
- NPE Completion
- CPE Completion

Aggregate Study
- Backlog Clearing Process

GI Study
- Cluster Study 1
- Cluster Study 2
- Cluster Study 3
- Facility Study 1
- Facility Study 2
- Facility Study 3

2014
Jan
Apr
Jul
Oct

2015
Jan
Apr
Jul
Oct

2016
Jan
Apr
Jul
Oct

Study Estimate Completion
NPE Completion
CPE Completion

New Process

Ag Study 1
Ag Study 2
Ag Study 3

Study Estimate Completion
Study Estimate Completion
Study Estimate Completion

Fac. Study 3
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<th>TRR Title</th>
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<table>
<thead>
<tr>
<th>Name</th>
<th>Matthew Harward</th>
</tr>
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<tbody>
<tr>
<td>E-mail Address</td>
<td><a href="mailto:mharward@spp.org">mharward@spp.org</a></td>
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<tr>
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<td>SPP</td>
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<tr>
<td>Phone Number</td>
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<th>Tariff Section(s) Requiring Revision</th>
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<td>Section No. Tariff, Article I, Section 13.7(c)</td>
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<th>Urgent (provided justification below for urgent request)</th>
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<table>
<thead>
<tr>
<th>Revision Description</th>
<th></th>
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<tbody>
<tr>
<td>Revision to Article I, Section 13.7(c) to provide a Tariff mechanism to distribute any penalty revenues collected by SPP pursuant to Section 13.7 (Classification of Firm Transmission Service) of the Tariff. The proposed mechanism provides that penalty revenues collected by SPP shall be used to reduce the Transmission Provider’s administrative costs to be recovered under Schedule 1-A. Any reduction in Schedule 1-A charges pursuant to this section applies to all Transmission Customers other than the penalized Transmission Customer.</td>
<td></td>
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</table>

<table>
<thead>
<tr>
<th>Reason for Revision</th>
<th>Pursuant to Section 13.7(c) of the Tariff, Transmission Customers that exceed its firm reserved capacity or uses Transmission Service at any Point of Receipt or Point of Delivery is subject to the applicable charge for the firm capacity actually used and a penalty of 100% of the Transmission Service charges under Schedules 7 and 11 for the period the unreserved service was used. Currently, this section provides that SPP shall compensate Transmission Owners for 100% of the Firm Transmission Service charge, the Base Plan Zonal charge and the Region-Wide Charge for the period for which the Transmission Owner provided service. However, the current Tariff is silent on how SPP distributes the penalty portion of the Transmission Customer’s charge.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>The Commission requires that a penalty mechanism be filed in the Tariff when the public utility has penalty revenues to distribute. FERC has approved the settlement agreement in Docket No. ER13-1032. Settlement documents are publicly available on SPP’s and FERC’s</td>
</tr>
</tbody>
</table>
website. As SPP will have penalty revenues to distribute upon satisfaction of the settlement payment, it is appropriate at this time to insert Tariff language describing the mechanism into the Tariff.

| Stakeholder Approval Required (specify date and record outcome of vote; n/a for those stakeholders not required) | MWG  
BPWG (n/a)  
TWG (n/a)  
ORWG (n/a)  
Other (specify) (n/a)  
RTWG 9-26-2013 – Approved with One Abstention (OPPD)  
MOPC  
Boa  
rd of Directors |
<table>
<thead>
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<tbody>
<tr>
<td>Legal Review Completed</td>
<td>❑ Yes (Include any comments resulting from the review)</td>
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<td></td>
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</tr>
<tr>
<td>Market Protocol Implications or Changes</td>
<td>❑ Yes (Include a summary of impact and/or specific changes &amp; PRR #)</td>
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<td>❑ No</td>
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<tr>
<td>Business Practice Implications or Changes</td>
<td>❑ Yes (Include a summary of impact and/or specific changes &amp; BPR #)</td>
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<tr>
<td></td>
<td>❑ No</td>
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<tr>
<td>Criteria Implications or Changes</td>
<td>❑ Yes (Include a summary of impact and/or specific changes)</td>
</tr>
<tr>
<td></td>
<td>❑ No</td>
</tr>
<tr>
<td>Other Corporate Documents Implications (i.e., SPP By-Laws, Membership Agreement, etc.)</td>
<td>❑ Yes (Include which corporate documents)</td>
</tr>
<tr>
<td></td>
<td>❑ No</td>
</tr>
</tbody>
</table>
### Credit Implications

- [ ] Yes *(Include a summary of impact and/or specific changes)*
- [x] No

### Impact Analysis Required

- [ ] Yes
- [x] No

---

**Proposed Tariff Language Revisions (Redlined)**

13.7 **Classification of Firm Transmission Service:**

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.3.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless (i) the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt, or (ii) the generating units or plants are in the same Control Area of a Transmission Owner in which case the units or plants also would be considered as a single Point of Receipt; provided, however, that generation which is dynamically scheduled shall be considered as part of the
Control Area where it is physically located. In the event of a change in the ownership or control of generation resources previously aggregated as a single Point of Receipt under this provision, such generation may be disaggregated and treated as multiple Points of Receipt, provided that all other terms of this Tariff and the Service Agreement are met. 

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedules 7 and 11. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. In the event that a Transmission Customer (including Third-Party Sales by a Transmission Owner) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved, the Transmission Customer shall pay the following penalty (in addition to
the applicable charges for all of the firm capacity actually used): 100% of the Firm Point-To-Point Transmission Service charges under Schedules 7 and 11 for the period for which the unreserved service was actually used. The charges for the unreserved service shall be based upon the duration of the period when the unreserved capacity was used. For example, one hour shall be billed at the charge for weekday deliveries, repeated daily use of unreserved capacity within a seven day period shall increase the duration of the period to a weekly duration and multiple instances of unreserved use during more than one seven day period during a calendar month shall increase the duration of the period to a monthly duration. The Transmission Provider shall compensate the Transmission Owners for 100% of the (i) Firm Point-To-Point Transmission Service charge, (ii) Base Plan Zonal Charge and (iii) Region-wide Charge for the period for which they have provided service. The penalty revenues in excess of that amount distributed to Transmission Owners shall be used to reduce the Schedule 1-A charges collected by the Transmission Provider from the Transmission Customers. All Transmission Customers, except the penalized Transmission Customer, shall receive a reduction of Schedule 1-A charges pursuant to this section. Such penalty revenues shall be distributed by the Transmission Provider to all Transmission Customers, except the penalized Transmission Customer, on a pro-rata basis of each Transmission Customer’s monthly Schedule 1-A charge, except the penalized Transmission Customer, for the next settlement billing period ending at least 15 calendar days after date the Transmission Provider collects the penalty revenues from the penalized Transmission Customer. For the amounts exceeding reserved capacity, the Transmission Customer also must replace losses as required by this Tariff.
Proposed Market Protocol Language Revision (Redlined)

n/a

Proposed Business Practices Language Revision (Redlined)

n/a

Proposed Criteria Language Revision (Redlined)

n/a

Revisions to Other Corporate Documents (Redlined)

n/a
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<td><strong>E-mail Address</strong></td>
<td><a href="mailto:mharward@spp.org">mharward@spp.org</a></td>
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<td>☐ Urgent (provided justification below for urgent request)</td>
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<td><strong>Revision Description</strong></td>
<td>Revision to Article I, Section 13.7(c) to provide a Tariff mechanism to distribute any penalty revenues collected by SPP pursuant to Section 13.7 (Classification of Firm Transmission Service) of the Tariff. The proposed mechanism provides that penalty revenues collected by SPP shall be used to reduce the Transmission Provider’s administrative costs to be recovered under Schedule 1-A. Any reduction in Schedule 1-A charges pursuant to this section applies to all Transmission Customers other than the penalized Transmission Customer.</td>
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<td>To make the Integrated Marketplace Tariff consistent with the penalty provision proposed in TRR 108.</td>
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<td>Other Corporate Documents Implications (i.e., SPP By-Laws, Membership Agreement, etc.)</td>
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13.7 **Classification of Firm Transmission Service:**

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.3.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are interconnected to the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless (i) the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt, or (ii) the generating units or plants comprise a registered Market Hub as defined in Attachment AE in which case the units or plants also would be considered as a single Point of Receipt. In the event of a change in the ownership or control of generation resources previously aggregated as a single Point of Receipt under this provision, such generation may be disaggregated and treated as multiple Points of Receipt, provided that all other terms of this Tariff and the Service Agreement are met.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for long-term firm Transmission Service along with a corresponding capacity reservation associated
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Proposed Market Protocol Language Revision (Redlined)

n/a
## Proposed Business Practices Language Revision (Redlined)

n/a

## Proposed Criteria Language Revision (Redlined)

n/a

## Revisions to Other Corporate Documents (Redlined)

n/a
Southwest Power Pool Staff, Inc.
MARKETS AND OPERATIONS POLICY COMMITTEE
Recommendation to the Board of Directors
Novation of KCP&L and KCP&L GMO to Transource Missouri
Nebraska City to Sibley and Iatan to Nashua 345kV Lines

October 29, 2013

Background:

KCP&L and KCP&L GMO propose to novate two projects to Transource Missouri, LLC:

1) Iatan to Nashua 345kV line, NTC-20042, ~$65 million dollars of investment, with a 2015 in-service date, a Balanced Portfolio Project

2) Sibley to Nebraska City 345kV line, NTC-20097, ~$380 million dollars of investment, 2017 in-service date, a Priority Project

Transource Missouri, LLC is a subsidiary of Transource Energy, a company jointly owned by American Electric Power and Great Plains Energy Inc. (GPE). GPE is the parent company of KCP&L and KCP&L GMO.

Per Attachment O, Section VI.6 of the SPP Open Access Transmission Tariff:

“At any time, a Designated Transmission Owner may elect to arrange for another entity or another existing Transmission Owner to build and own all or part of the project in its place subject to the qualifications in Subsections i, ii, iii, and iv above.”

Per SPP Business Practice 7070, a novation is defined as:

“A novation is the release of the original DTO’s obligation to ensure that a project is built. After the DTO’s assignment of the right to build and the approval and execution of a novation, the new TO will have the right and obligation to build the project.”

Analysis:

Quanta Technologies was retained to perform a due diligence review of the proposed novation. Quanta’s findings were summarized in three primary areas:

1) Financing Assumptions
2) Cost to SPP Customers
3) Project Development, Operations, and Maintenance

- Capital cost of project essentially same for Transource as for KCP&L GMO. Cost could be lower for Transource when the buying power of AEP is used to procure equipment and materials.

- Approximately $5.8M in savings to the Transmission Customers over 40 years on a net present value basis (2013$) was estimated.
- Savings to Transmission Customers were due to reduced ROE and long-term debt costs of Transource Missouri verses KCP&L GMO.

- From the Quanta Due Diligence report, “It is the opinion of Quanta Technology that the approach chosen by Transource to develop, operate and maintain the Project is equivalent or superior to KCPL developing, operating and maintaining the Project.”

Additionally, Missouri Public Service Commission (MPSC) granted the application of transfer from KCP&L and KCP&L GMO certain assets (associated with this Novation) to Transource Missouri, LLC. The MPSC also granted Transource Missouri, LLC’s application for a Certificate of Convenience and Necessity.

**Conclusion of the MOPC:**

During the MOPC meeting on Oct 16th, 2013, Bary Warren, (Empire District) made a motion, seconded by Walt Shumate (Hunt Transmission), to endorse the Quanta Report on this proposed novation as presented. The motion unanimously passed with eight abstentions: ITC Great Plains, KPP, Flat Ridge 2 Wind Energy, Xcel Energy, American Transmission, City of Coffeyville and Exelon Power.

**Action Requested:**

It is requested that the SPP Board of Directors approve the novation of the 345kV lines from Nebraska City to Sibley and Iatan to Nashua from KCP&L and KCP&L GMO to Transource Missouri, LLC.

---

1 Quanta’s Due Diligence Review of the novation, dated October 4, 2013, pg. 10.

2 Missouri Public Service Commission File No. EA-2013-0098, Effective Date: September 6, 2013, pg. 17.
Southwest Power Pool Staff, Inc.
MARKETS AND OPERATIONS POLICY COMMITTEE
Recommendation to the Board of Directors
Novation of KCP&L and KCP&L GMO to Transource Missouri
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**Action Requested:**

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---

¹ Quanta’s Due Diligence Review of the novation, dated October 4, 2013, pg. 10.

² Missouri Public Service Commission File No. EA-2013-0098, Effective Date: September 6, 2013, pg. 17.
Southwest Power Pool, Inc.
MARKETS AND OPERATIONS POLICY COMMITTEE
Recommendation to the Board of Directors
October 29, 2013
Bowers – Howard 115 kV Recommendation

Organizational Roster
Terri Gallup (Chair), AEP
David Kimball (Vice-Chair), NPPD
Al Ackland, KCPL
Scott Benortham, Westar
Brent Carr, AECC
Peter Day, OG&E
Tom Hestermann, Sunflower
Larry Holloway, KPP
Leland Jacobson, OPPD
Lloyd Kolb, Golden Spread
Tom Littleton, OMPA
Thomas Maldonado, SPS
Brian Slocum, ITC Great Plains
Jeff Stebbins, Tri-County Electric
John Krajewski, Nebraska Power Review Bd.
(CAWG Liaison)
Cary Frizzell, SPP Staff Secretary

Background
The PCWG reviews projects in accordance with SPP Business Practice 7060 which establishes applicable precision bandwidths for construction projects.

SPP identified the project as a solution to mitigate voltage issues at the Bowers Interchange and Grapevine area in SPS as a part of the 2012 ITP Near-Term Assessment (ITPNT). The project scope consists of constructing a new 33-mile 115 kV line from Bowers Interchange to the Howard substation and installing a second 115/69 kV transformer at Bowers. SPP issued NTC No. 200166 to SPS that included Bowers – Howard 115 kV on April 9, 2012 with a total project cost estimate listed at $17,407,520.

On September 3, 2012, SPS submitted an NTC Project Estimate (NPE) of $23,709,821 to SPP for the project, an increase of 36.2% from the Study Estimate listed on the NTC. SPP then re-evaluated the project as a part of the 2013 ITPNT. The need for the project was determined to continue to exist with the identified solution still considered the appropriate regional solution and required acceleration to mitigate the potential reliability issues identified.

At the same time, the project was also being studied as a solution to added load delivery points submitted in an Attachment AQ request. As a result, SPP issued NTC No. 200190 to SPS on January 18, 2013 to fulfill the delivery point requests in the SPS/Golden Spread Electric Coop. area as detailed in Delivery Point Network Study DPA-2011-September-095. The NTC accelerated the Need Date for Bowers – Howard 115 kV from June 1, 2016 to June 1, 2013. SPS submitted a commitment to construct the project on April 17, 2013, and an NPE of $25,557,920 was accepted.

On August 16, 2013, SPS submitted an update of $33,951,077 to the cost estimate for Bowers – Howard 115 kV during the Quarterly Project Tracking update cycle for Q4 2013. This constituted a 32.8% increase from the baseline cost of the project.
Analysis

SPS noted that the primary reason for the cost increase as the settlement route selected by the PUC for the new 115 kV transmission line. As stated in Docket No. 40550, the PUC required SPS to wreck-out the existing 69 kV line connecting the Bowers Interchange and Howard end points and rebuild with double-circuit structures using the same ROW to accommodate the 69 kV replacement line and the new 115 kV line included in NTC No. 200190. The PUC concluded that the existing 69 kV line was well past its expected useful life, and that building the two lines with double-circuit structures was be the most total cost effective solution.

SPS estimated the added cost of materials for the double-circuit structures as $5,257,613 and the added cost of labor as $3,015,873. The rest of the increase in the total project cost estimate was due to an updated estimate to the transformer at Bowers which increased by $119,671.

SPS expects the project to be placed into service by June 1, 2015, though construction has not started on the project, as of the time in which SPS provided their project variance report to SPP on August 30.

Recommendation

The MOPC recommends that the cost estimate deviation recognized in the Q4 2013 Project Tracking update for Bowers – Howard 115 kV be accepted as reasonable and acceptable, and that the baseline cost be reset to the new value.

Approved:

MOPC
Passed Unanimously

October 15-16, 2013

PCWG
Approved with one abstention (Golden Spread)

September 9, 2013

Action Requested: Approve Recommendation

1 http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40550_131_759631.PDF
Southwest Power Pool, Inc.

HUMAN RESOURCES COMMITTEE

Recommendation to the SPP Board of Directors

Amended and Restated Pension Plan Recommendation

September 10, 2013

Organizational Roster

The following members represent the Human Resources Committee:

- Ms. Phyllis Bernard, Chair
- Mr. Julian Brix
- Ms. Lori Dunn
- Mr. Duane Highley
- Mr. Mike Palmer
- Mr. Noman Williams

- SPP Director
- SPP Director
- Calpine Corporation
- Arkansas Electric Cooperative Corporation
- Empire District Electric Company
- Sunflower Electric Power Corporation

Background

Pursuant to Internal Revenue Procedure 2005-66, the Southwest Power Pool Defined Benefit Retirement Plan Document must be restated every five years. The Internal Revenue Service requires that qualified plans be periodically restated to incorporate changes resulting from law and regulation changes and any plan amendments since the last restatement.

Analysis

The SPP Defined Benefit Retirement Plan, “Southwest Power Pool, Inc. Retirement Plan” (“Plan”), has been reviewed and restated to comply with the IRS requirements. The Plan must be filed no later than January 1, 2014 to meet the IRS requirements.

Since last filed with the IRS, SPP has made several substantive changes to its pension plan as follows:

1. Added language to comply with the Heroes Earnings Assistance and Relief Act (HEART Act) of 2008. This law provides additional tax and pension benefits to individuals who are absent from work due to duty in uniformed military service.
2. Changed employee vesting schedule from three to five years.
3. More clearly defined fiduciary and plan administrator and associated responsibilities.

In addition to the changes initiated by SPP, several non-substantive changes have been made to the plan to comply with pension regulations and, additionally, several other changes have been made to improve the “readability” of the plan.

Recommendation

The Human Resources Committee recommends Southwest Power Pool Board of Directors approve the amended and restated pension plan document and direct SPP to file the amended and restated pension plan document with the IRS.

Approved: Human Resources Committee

Action Requested: Approve Recommendation

September 10, 2013
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ARTICLE 1. INTRODUCTION

Southwest Power Pool, Inc. (“Company”) hereby amends and restates its plan, originally effective January 1, 1996, to provide the retirement benefits for its eligible Employees in addition to those provided under the Federal Social Security Act. Such plan shall be known as the “Southwest Power Pool, Inc. Retirement Plan” (“Plan”).
ARTICLE 2. DEFINITIONS

The following words and phrases when used herein shall have the following meanings, except as otherwise required by the context. The masculine pronoun wherever used shall include the feminine, and the feminine pronoun shall include the masculine. Wherever any words are used herein in the singular, they shall be construed as though they were also used in the plural in all cases where they shall so apply.

2.1 “ACTUARIAL EQUIVALENT” means a benefit payable at a particular time and in a particular form and manner and which has the same value as the benefit which it replaces. Such equivalent amount of the Base Benefit which is provided under the normal or optional forms of Retirement Income under Article 7 shall be determined in accordance with the adjustment factors set forth in Appendix A to the Plan, which is entitled “Table of Adjustment Factors for Determining Actuarial Equivalence.”

For Plan Years beginning prior to January 1, 2008, the Actuarial Equivalent for purposes of determining the present value of a lump sum distribution under the Plan shall be made using the annual interest rate on 30 year Treasury securities as published in the Internal Revenue Bulletin for the second full month preceding the first day of the Plan Year which rate shall remain constant for the Plan Year. The Actuarial Equivalent for such purposes shall be made using the following mortality table: (a) for annuity starting dates before January 1, 2003, the mortality projections taken from the 1983 Group Annuity Mortality Table with a 50 percent male and 50 percent female weighting of the mortality rates as described in Revenue Ruling 95-6; and (b) for annuity starting dates on or after January 1, 2003 and before January 1, 2008, the mortality table described in Revenue Ruling 2001-62 or the successor mortality tables as prescribed by the Secretary of the Treasury.

For Plan Years beginning after December 31, 2007, the Actuarial Equivalent for purposes of determining the present value of a lump sum distribution shall be determined using (a) the applicable mortality table, as determined under Code section 417(e)(3)(B), and (b) the applicable interest rate, as determined under Code section 417(e)(3)(C).

For persons terminating employment after December 31, 2007 and before August 1, 2008 to whom a lump sum is payable under the Plan, calculation shall be made using the lump sum actuarial equivalent factors which produce the higher lump sum value. The stability period shall be one plan year. The interest rate shall be determined as of the first of the second month before the beginning of the applicable plan year.

2.2 “AFFILIATE” shall mean

(a) Any corporation other than the Company, i.e., either a subsidiary corporation or an affiliated or associated corporation of the Company, which together with the
Company is a member of a “controlled group” of corporations (as defined in Code Section 414(b));

(b) Any organization which together with the Company is under “common control” (as defined in Code Section 414(c));

(c) Any organization which together with the Company is an “affiliated service group” (as defined in Code Section 414(m));

(d) Any organization required to be aggregated with an Employer pursuant to Code Section 414(o); or

(e) Any other corporation or entity designated as an Affiliate by resolution of the Board of Directors of the Company.

2.3 “BENEFICIARY” shall mean any Joint Annuitant, surviving spouse or any other person entitled to a benefit under the Plan.

2.4 “BENEFIT BASE” shall mean the amount of Retirement Income provided in Article 6, and as otherwise modified pursuant to the Plan.

2.5 “BENEFIT SERVICE” shall mean a Participant’s service, not in excess of 40 years and credited in accordance with Section 3.3, used together with his Final Average Monthly Earnings to determine the amount of his Benefit Base.

2.6 “BOARD OF DIRECTORS” shall mean the Board of Directors of the Company.

2.7 “BREAK IN SERVICE” shall mean a period of at least 12 consecutive months, commencing on an Employee’s Severance Date, during which an Employee is not directly or indirectly paid, or entitled to payment, by the Company or an Affiliate for an hour of service. In the case of an Employee who is absent from work for a leave of absence authorized by the Company, or by any Affiliate employing the Employee at the time the leave is requested, the period of such absence, not to exceed two years, shall not constitute a Break In Service. In the case of an Employee who is absent from work due to service in the military forces of the United States, the period of such absence shall not constitute a Break In Service if the Participant returns to the employment of the Company or an Affiliate within the reemployment period specified in Code Section 414(u). In the case of an Employee who is absent from work for maternity or paternity reasons, the 12-consecutive month period beginning on the first anniversary of the first date of such absence shall not constitute a Break In Service. For purposes of this definition, an absence from work for maternity or paternity reasons means an absence (1) by reason of the pregnancy of the Employee, (2) by reason of the birth of a child of the Employee, (3) by reason of the placement of a child with the Employee in connection with the adoption of such child by such
Employee, or (4) for purposes of caring for such child for a period beginning immediately following such birth or placement.

2.8 “CODE” shall mean the Internal Revenue Code of 1986, as amended.

2.9 “COMMITTEE” shall mean the Committee, as from time to time composed, as appointed by the Board of Directors pursuant to Article 14 to operate and administer the Plan.

2.10 “COMPANY” shall mean Southwest Power Pool, Inc. or any successor thereto.

2.11 “EARNINGS” shall mean, (1) for amounts paid before February 1, 2007, the amounts paid to an Employee by the Company with respect to services rendered as reported on the Employee’s Federal Income Tax Withholding Statement (Form W2 or its equivalent) as determined without regard to any rules that limit the remuneration included in wages based on the nature or location of the employment or the services performed; (2) for amounts paid after January 31, 2007, the amounts paid to an Employee by the Company as base salary, and excluding bonuses, overtime and other extraordinary compensation. Earnings shall not include amounts included in income under section 457(f). Earnings shall also include elective contributions under a cash or deferred arrangement qualified under Section 401(k) of the Code, under a tax sheltered annuity under Section 403(b) of the Code, or under Section 457(b) of the Code, Section 125 of the Code or Section 132(f)(4) of the Code.

Notwithstanding the above, Earnings shall not include any lump sum payment of accrued vacation to an Employee terminating employment from the Company.

In addition to the foregoing, solely with respect to Participants in the Initial Group, “Earnings” shall mean regular monthly earnings received from Entergy or its affiliates prior to the original Effective Date as determined in accordance with the terms of the Prior Plan.

A Participant who becomes disabled and is entitled to receive benefits from the Company’s long term disability plan, shall be considered as remaining employed by the Company for the Period of Service provided in Section 3.1, at the rate of Earnings and for the regularly scheduled number of hours last in effect immediately prior to becoming so eligible.

For Plan Years beginning before January 1, 2002, an employee’s total Earnings taken into account under the Plan for any Plan Year shall not exceed the following:

<table>
<thead>
<tr>
<th>Year</th>
<th>Earnings</th>
</tr>
</thead>
<tbody>
<tr>
<td>1996</td>
<td>$150,000</td>
</tr>
<tr>
<td>1997</td>
<td>$160,000</td>
</tr>
<tr>
<td>1998</td>
<td>$160,000</td>
</tr>
<tr>
<td>1999</td>
<td>$160,000</td>
</tr>
</tbody>
</table>
For Plan Years beginning after December 31, 2001, an Employee’s total Earnings taken into account under the Plan for any Plan Year shall not exceed Two Hundred Thousand Dollars ($200,000) (as adjusted in accordance with Section 401(a)(17) of the Code).

Earnings means compensation during the Plan Year or such other consecutive twelve (12) month period over which Earnings are otherwise determined under the Plan (the determination period).

Earnings shall include regular pay after severance of employment if: (i) the payment is regular compensation for services during the Participant's regular working hours and would otherwise have been included in Earnings under this section and (ii) the payment would have been paid to the Participant prior to a severance from employment if the Participant had continued in employment with the Employer; and (iii) is paid within 2 ½ months of termination of employment.

Differential wage payments, as defined in Code section 3401 as amended by the HEART Act, shall not be included in Earnings.

“EFFECTIVE DATE” shall mean January 1, 2008, unless otherwise stated herein. The required provisions of this Plan relating to EGTRRA shall be effective the first day of the Plan Year beginning in 2002, unless otherwise required.

“EMPLOYEE” shall mean any person on the payroll of the Employer whose wages from the Employer are subject to withholding for the purposes of Federal income taxes and for the purposes of the Federal Insurance Contributions Act.

Employees shall include persons employed by Affiliated Employers and persons who are leased employees under § 414(n).

An individual who is not classified for the relevant period as an employee on the Employer’s (or Affiliated Employer’s) payroll records, whether because the individual is treated as an independent contractor or an employee of another person, shall not be an Employee, even if such classification is determined to be erroneous, or is retroactively revised pursuant to an audit by a governmental agency, civil litigation or otherwise, and even though such individual’s pay shall be later determined to be subject to withholding as an employee for previous periods.

“EMPLOYMENT COMMENCEMENT DATE” (or in the case of reemployment following a Severance Date, (“Reemployment Commencement Date”) shall mean the first date on which an Employee is directly or indirectly paid, or entitled to payment by the Company or an Affiliate for an hour of service.
2.15 “ERISA” shall mean the Employee Retirement Income Security Act of 1974, as amended.

2.16 “FINAL AVERAGE MONTHLY EARNINGS” shall mean the Participant’s average monthly Earnings for the highest consecutive 60 months during the 120 months immediately preceding his date of death, retirement, termination of employment, or transfer from the Company to an Affiliate, whichever occurs first. If a Participant has fewer than 60 months of Earnings with the Employer, all of the Participant’s Earnings will be counted. Periods when a Participant is not employed by the Company are not considered when determining Final Average Monthly Earnings.

2.17 “FUND” shall mean the trust fund provided pursuant to the Trust Agreement and held by the Trustee, to which contributions under the Plan will be made, and out of which benefits under the Plan will be paid or otherwise provided for as hereinafter set forth.

2.18 “INITIAL GROUP” shall mean the group Participants who (a) were employees of Entergy or any of its subsidiaries before becoming Employees of the Company; (b) were participants under the Prior Plan immediately prior before becoming Employees of the Company; and (c) became Employees of the Company during 1996.

2.19 “INVESTMENT MANAGER” shall mean any investment manager appointed by the Plan Administrator pursuant to Section 13.1. An Investment Manager shall be an investment adviser registered under the Investment Advisers Act of 1940, a bank as defined in said Act, or an insurance company qualified to perform investment management services under the laws of more than one state. An investment Manager hereunder must acknowledge in writing that it is a fiduciary with respect to the Plan.

2.20 “JOINT ANNUITANT” shall mean the Participant’s spouse under Section 7.1(a) or the person designated by a Participant under Section 7.2 of the Plan to receive a life income in the event of the Participant’s death after his Retirement Income Commencement Date.

2.21 “LEASED EMPLOYEE” shall mean any person (other than an Employee of the recipient) who pursuant to an agreement between the recipient and any other person (“leasing organization”) has performed services for the recipient (or for the recipient and related persons determined in accordance with Section 414(n)(6) of the Code) on a substantially full-time basis for a period of at least one year, and such services are performed under the primary direction or control by the recipient employer. Contributions or benefits provided a leased employee by the leasing organization which is attributable to services performed for the recipient employer shall be treated as provided by the recipient employer.

2.21 “ORIGINAL EFFECTIVE DATE” shall mean January 1, 1996.
2.22 "PARTICIPANT" shall mean any person who satisfies the eligibility requirements for participation in accordance with Article 4.

2.23 "PERIOD OF SERVICE" shall mean the aggregate of an Employee’s periods of employment with the Company or with an Affiliate, as credited in accordance with Section 3.1, and used to determine the Benefit Service and Vesting Service under the Plan.

2.24 "PLAN" shall mean the Southwest Power Pool, Inc. Retirement Plan, and any amendments thereto.

2.25 "PLAN ADMINISTRATOR" shall mean the person or committee, as from time to time composed, as appointed by the Board of Directors pursuant to Article 14 to operate and administer the Plan.

2.26 "PLAN YEAR" shall mean the calendar year.

2.27 "PRIOR PLAN" shall mean the defined benefit plan qualified under Code § 401(a) and maintained by a member of Southwest Power Pool, Inc., in which an Employee of the Company participated immediately prior to employment with the Company, provided the Employee is given credit for service with such member as provided in Section 3.1 hereof.

2.28 "RETIREMENT INCOME" shall mean the benefits payable under the Plan.

2.29 "RETIREMENT INCOME COMMENCEMENT DATE" shall mean the first day of the first period with respect to which a Retirement Income is received (or receivable) by a Participant.

2.30 "SEVERANCE DATE" shall mean the earlier of: (i) the date an Employee quits, is discharged or retires from the Company or an Affiliate, or (ii) the later of the first anniversary of the first day he is absent from service from the Company or an Affiliate for any other reason or the commencement of a Break In Service.

2.31 "SOCIAL SECURITY RETIREMENT AGE" shall mean the age used as the retirement age for a Participant under Section 216(l) of the Social Security Act, except that such section shall be applied without regard to the age increase factor, as if the early retirement age under Section 216(l)(2) of such Act were 62.

2.32 "TRUST AGREEMENT" shall mean any agreement in the nature of a trust, or in the nature of a custodial or funding agreement (including any group annuity contract and/or funding investment contract issued pursuant thereto) between the Company and the Trustee and/or insurer, that is established to form a part of the Plan to receive, hold, invest, and dispose of the Fund.
2.3233 “TRUSTEE” shall mean the Trustee or Trustees named in the Trust Agreement and/or the insurer named in any other funding agreement, and any additional or successor Trustee or Trustees from time to time acting as Trustee or Trustees of the trust assets under the Plan, or the insurer acting in the capacity of a custodian or funding agent of such trust assets.

2.3334 “VESTING SERVICE” shall mean a Participant’s Period of Service, as credited in accordance with Section 3.2, used to determine his entitlement to Retirement Income under the Plan.
ARTICLE 3. CREDITED SERVICE

3.1 Period of Service

An Employee’s Period of Service shall mean the period of the Employee’s service with the Company or with an Affiliate commencing on his Employment Commencement Date (or Reemployment Commencement Date) and ending on his Severance Date. Except as otherwise provided in this Article 3, all Periods of Service shall be aggregated.

For Employees hired before November 1, 2005, in addition to the foregoing, the Period of Service shall include any Period of Service accrued during service with any company which is a member of Southwest Power Pool, Inc. at the time such Employee first becomes employed by the Company, provided (1) that the Employee was employed by such member immediately prior to becoming an Employee of the Company and (2) such Employee was a participant in a qualified defined benefit pension plan maintained by such member. Such Period of Service shall be recognized as Vesting Service and/or Benefit Service under Plan Sections 3.2 and 3.3; provided, however, that in no event shall any service be counted more than once for the same purpose.

For eligibility and vesting purposes, if an Employee quits, is discharged, or retires, and is subsequently reemployed within twelve (12) months of his Severance Date, the period between his Severance Date and his Reemployment Commencement Date shall be included in his Period of Service; Benefit Service for purposes of calculating a Participant’s benefit shall not include any period between severance and reemployment. If such Employee quits, is discharged or retires during a period of absence from service for other reasons, his Period of Service shall include the period between his Severance Date and his Reemployment Commencement Date for vesting purposes only if he is Reemployed within twelve (12) months of his Severance Date.

A Participant’s Period of Service shall also include periods during which the Participant is receiving benefits under a Company sponsored short term or long term disability plan until the earlier of: (i) the last day of the month in which such Participant ceases to be eligible to receive payment under either disability program, or (ii) the Participant’s Retirement Income Commencement Date.

3.2 Vesting Service

Vesting Service creditable under the Plan shall include an Employee’s Period of Service, excluding any service prior to the date on which a Participant attains age 18.

3.3 Benefit Service

(a) Benefit Service creditable under the Plan shall be equal to an Employee’s Period of Service, excluding any service prior to the date on which a Participant attains age 21.
(b) Benefit Service shall also include periods of leave of absence for service in the Military Forces of the United States, if the Participant returns to the employment of the Company or an Affiliate within the reemployment period specified in Code Section 414(u).

(c) Any other provision of the Plan to the contrary notwithstanding, a Participant’s Benefit Service shall not include any service with any Affiliate.

3.4. Break In Service

(a) A former Participant or an inactive Participant who has a Break In Service shall not be credited with Vesting Service or Benefit Service following such Break In Service until he resumes active participation in the Plan. He shall be deemed to have become a Participant as of his Reemployment Commencement Date.

(b) In case of a vested Participant who incurs a Break In Service, his Vesting Service and his Benefit Service prior to the Break In Service will be restored to him upon resumption of participation in the Plan.

(c) In case of a nonvested Participant who commences a Break In Service, his Vesting Service and his Benefit Service prior to the Break In Service will be restored unless the period of such Break In Service equals or exceeds the greater of: (i) 5 years or (ii) the period of Vesting Service or Benefit Service (as the case may be) prior to such break. Such period shall not include any service not taken into account by reason of any prior Break In Service.
ARTICLE 4. PARTICIPATION

4.1. New Participants

Any Employee shall become a Participant in the Plan on the first day of the month following the attainment of age 21 or the first day of the month following his Employment Commencement Date, whichever is later.

If an Employee on or after the Effective Date attains age 21 during a period of absence from service for reasons other than termination of employment and is Reemployed prior to a Severance Date, he shall become a Participant as of the first of the month next following the attainment of age 21. If an Employee on or after the Effective Date attains age 21 during a period of absence from service and after a Severance Date, he shall become a Participant on the first day of the month following his Reemployment Commencement Date.

4.2. Cessation of Participation

Each person who qualifies as a Participant under the provisions of the preceding Sections of this Article shall continue to be such until his Severance Date; provided, however, that a Participant shall not cease to be such if he is vested and entitled to a Retirement Income under Article 6 or Article 10 but he shall be treated as an inactive Participant.

4.3. Reinstatement.

A former Participant or an inactive Participant who has a Break In Service shall again become a Participant in the Plan as of his Reemployment Commencement Date.
ARTICLE 5. RETIREMENT DATES

5.1. Normal Retirement Date

A Participant shall have a nonforfeitable right to his accrued benefit when he attains the age of 65, and his Normal Retirement Date shall be his 65th birthday.

5.2. Early Retirement Date

(a) Upon 30 days prior written notice to the Company, a Participant who has completed 10 years of Vesting Service may elect to retire at an Early Retirement Date, which may be any day within the 10-year period immediately preceding the Participant’s Normal Retirement Date.

(b) A Participant who elects to retire at an Early Retirement Date may file a written request with the Company to commence his Retirement Income prior to his Normal Retirement Date pursuant to Section 6.3.

5.3. Deferred Retirement Date

If Participant continues in active employment with the Company (or with an Affiliate, if he is in the employ of such an Affiliate at his Normal Retirement Date) after his Normal Retirement Date, his Deferred Retirement Date shall be the date of his actual separation from the service of the Company and any Affiliate.

5.4. Commencement of Distributions

(a) Unless otherwise elected by the Participant in writing, payment of benefits under the Plan to a Participant shall begin not later than the sixtieth (60th) day after the close of the Plan Year in which the latest of the following occurs:

(i) the date on which the Participant attains the earlier of age 65 or the normal retirement age specified under the Plan,

(ii) the tenth (10th) anniversary of the date the Participant commenced participation in the Plan, or

(iii) the date the Participant terminates his service with the Employer.

An election shall be made by submitting to the Plan Administrator a written statement, signed by the Participant, which describes the benefit and the date on which the payment of such benefit may commence. The failure of a Participant (and spouse) to consent to a distribution
while the benefit is immediately distributable shall be deemed to be an election sufficient to satisfy this provision.

(b) Notwithstanding the above, a Participant’s entire interest will be distributed, or begin to be distributed, to the Participant no later than the Participant’s required beginning date in accordance with the final regulations under section 401(a)(9).

(b) All distributions under the plan shall be in accordance with the rules of section 401(a)(9) of the Code, including the Incidental Death Benefit rule of Code section 401(a)(9)(G). Required minimum distributions will be made in accordance with 1.401(a)(9)-1 through 1.401(a)(9)-9 of the Final Regulations that were published on April 17, 2002. The provisions reflecting 401(a)(9) override any distribution options in the Plan to the contrary.

(c) If the participant’s interest is paid in the form of annuity distributions under the plan, payments under the annuity will satisfy the following requirements:

(i) the annuity distributions will be paid in periodic payments made at intervals not longer than one year.

(ii) the distribution period will be over a life (or lives) or over a period certain not longer than the period described in paragraphs (f) and (g);

(iii) once payments have begun over a period certain, the period certain will not be changed even if the period certain is shorter than the maximum permitted;

(iv) payments will either be nonincreasing or increase only as follows:

(1) by an annual percentage increase that does not exceed the annual percentage increase in a cost-of-living index that is based on prices of all items and issued by the Bureau of Labor Statistics;

(2) to the extent of the reduction in the amount of the participant’s payments to provide for a survivor benefit upon death, but only if the beneficiary whose life was being used to determine the distribution period dies or is no longer the participant’s beneficiary pursuant to a qualified domestic relations order within the meaning of section 414(p);

(3) to provide cash refunds of employee contributions upon the participant’s death; or

(4) to pay increased benefits that result from a plan amendment.

(d) The amount that must be distributed on or before the participant’s required beginning date is the payment that is required for one payment interval. The second payment need not be made until the end of the next payment interval even if that payment interval ends in
the next calendar year. Payment intervals are the periods for which payments are received, e.g., bi-monthly, monthly, semi-annually, or annually. All of the participant’s benefit accruals as of the last day of the first distribution calendar year will be included in the calculation of the amount of the annuity payments for payment intervals ending on or after the participant’s required beginning date.

(e) Any additional benefits accruing to the participant in a calendar year after the first distribution calendar year will be distributed beginning with the first payment interval ending in the calendar year immediately following the calendar year in which such amount accrues.

(f) If the participant’s interest is being distributed in the form of a joint and survivor annuity for the joint lives of the participant and a nonspouse beneficiary, annuity payments to be made on or after the participant’s required beginning date to the designated beneficiary after the participant’s death must not at anytime exceed the applicable percentage using the table set forth in Q&A-2 of section 1.401(a)(9)-6 of the Treasury regulations. If the form of distribution combines a joint and survivor annuity for the joint lives of the participant and a nonspouse beneficiary and a period certain annuity, the requirement in the preceding sentence will apply to annuity payments to be made to the designated beneficiary after the expiration of the period certain.

(g) Unless the participant’s spouse is the sole designated beneficiary and the form of distribution is a period certain and no life annuity, the period certain for an annuity distribution commencing during the participant’s lifetime may not exceed the applicable distribution period for the participant under the Uniform Lifetime Table set forth in section 1.401(a)(9)-9 of the Treasury regulations for the calendar year that contains the annuity starting date. If the annuity starting date precedes the year in which the participant reaches age 70, the applicable distribution period for the participant is the distribution period for age 70 under the Uniform Lifetime Table set forth in section 1.401(a)(9)-9 of the Treasury regulations plus the excess of 70 over the age of the participant as of the participant’s birthday in the year that contains the annuity starting date. If the participant’s spouse is the participant’s sole designated beneficiary and the form of distribution is a period certain and no life annuity, the period certain may not exceed the longer of the participant’s applicable distribution period, as determined under this paragraph, or the joint life and last survivor expectancy of the participant and the participant’s spouse as determined under the Joint and Last Survivor Table set forth in section 1.401(a)(9)-9 of the Treasury regulations, using the participant’s and spouse’s attained ages as of the participant’s and spouse’s birthdays in the calendar year that contains the annuity starting date.

(h) Definitions.

(i) Designated Beneficiary. The individual who is designated as the beneficiary under the plan and is the designated beneficiary under section 401(a)(9) of the Internal Revenue Code and section 1.401(a)(9)-4 of the Treasury regulations.
(ii) Distribution Calendar Year. A calendar year for which a minimum distribution is required. For distributions beginning before the participant’s death, the first distribution calendar year is the calendar year immediately preceding the calendar year which contains the participant’s required beginning date. For distributions beginning after the participant’s death, the first distribution calendar year is the calendar year in which distributions are required to begin under section 2.2.

(iii) Life Expectancy. Life expectancy as computed by use of the Single Life Table in section 1.401(a)(9)-9 of the Treasury regulations.

(iv) Required Beginning Date. April 1 of the calendar year following the year in which the participant (i) attains age 70 ½, or if later (ii) retires.
ARTICLE 6. PARTICIPANTS BENEFIT BASE

6.1. Benefit Base

Except as otherwise provided in the Plan, a Participant’s Benefit Base shall be an annuity for life, commencing on the first day of the calendar month next following his Normal Retirement Date, under which the monthly payment shall be equal to one and one-half percent (1 ½%) of his Final Average Monthly Earnings multiplied by his years of Benefit Service not to exceed 40 years of Benefit Service. For purposes of determining a Benefit Base for a Participant who is given credit for service with a member of Southwest Power Pool, Inc. pursuant to Section 3.1, the amount of the monthly annuity payment determined in accordance with the preceding sentence shall be reduced by deducting therefrom the amount of any vested benefit from employer contributions, expressed as a monthly annuity for life commencing at Normal Retirement Date, which the participant earned under the Prior Plan, regardless of whether the Participant received a paid up benefit or cash payment in lieu thereof or a refund of an employee contribution under such member’s plan. The benefit a participant receives from this Plan shall be the greater of (1) the Benefit Base calculated using only service with the Company or (2) the Benefit Base calculated using all years of Benefit Service included under Section 3.1. Immediately on employment of an Employee who was previously employed by a member, the Plan Administrator shall obtain from the Prior Plan the amount of such vested benefit.

6.2. Normal Retirement

A Participant who retires from the Company (or from any Affiliate, if the Participant is in the employ of such an Affiliate at that time) on his Normal Retirement Date shall be entitled to a monthly Retirement Income in the normal form or any optional form made available under Article 7 of the Plan, commencing on the first day of the calendar month next following his Normal Retirement Date. Such a Participant’s Benefit Base shall be computed as in Section 6.1, and the normal or optional form of his Retirement Income shall be the Actuarial Equivalent of his Benefit Base so computed.

6.3. Early Retirement

A Participant who retires from the Company (or from any Affiliate, if the Participant is in the employ of such an Affiliate at that time) on an Early Retirement Date shall be entitled to a monthly Retirement Income in the normal form or any optional form made available under Article 7 of the Plan commencing on the first day of the calendar month next following his Normal Retirement Date, or if elected by such Participant pursuant to Section 5.2(b), on the first day of the calendar month next following his Early Retirement Date. Such a Participant’s Benefit Base shall be computed as in Section 6.1 without application of any reduction based on benefits earned under the Prior Plan, but reduced as follows:
(1) With respect to the grandfathered participants described below, the reduction shall be 1/6 of 1 percent for each month by which his Retirement Income Commencement Date precedes the first day of the calendar month next following his Normal Retirement Date.

(2) With respect to Participants other than the grandfathered Participants described below, with respect to the portion of the Participant’s Accrued Benefit at the Participant’s Retirement Commencement Date which accrued before January 1, 2007, the reduction shall be 1/6 of 1 percent for each month by which his Retirement Income Commencement Date precedes the first day of the calendar month next following his Normal Retirement Date. The portion accruing before January 1, 2007 shall be the Participant’s Accrued Benefit at December 31, 2006, divided by the total Accrued Benefit at the Participant’s Retirement Commencement Date.

(3) With respect to Participants other than the grandfathered Participants described below, with respect to that portion of the Participant’s Accrued Benefit at the Participant’s Retirement Commencement Date which accrued after December 31, 2006, the reduction shall be ½ of 1 percent for each month by which his Retirement Income Commencement Date precedes the first day of the calendar month next following his Normal Retirement Date. The portion accruing after December 31, 2006, shall be the participant’s total accrued benefit at retirement, less the Participant’s Accrued Benefit at December 31, 2006.

For purposes of this Section, the grandfathered Participants shall be Participants who have attained at least the age of 45 and have at least five (5) Years of Vesting Service at December 31, 2006, plus the Initial Group.

The normal or optional form of his Retirement Income shall be the Actuarial Equivalent of his Benefit Base as computed above. The amount of the monthly life annuity payment determined in accordance with the above shall be reduced by deducting therefrom the amount of any vested benefit, expressed as a monthly annuity for life commencing at such Early Retirement Date, which the Participant earned under any Prior Plan subject to any applicable reductions but regardless of whether the Participant received a paid-up benefit or a cash payment in lieu thereof or a refund of his Accumulated Contributions as defined in any Prior Plan.

6.4. Deferred Retirement

(a) If a Participant continues in active employment with the Company (or with any Affiliate, if he is in the employ of such an Affiliate at his Normal Retirement Date) after his Normal Retirement Date, the payment of his Retirement Income under Section 6.2 shall be suspended in accordance with Section 203(a)(3)(B) of ERISA.

(b) A Participant who retires from the Company (or from any Affiliate, if the Participant is in the employ of such an Affiliate at that time) on a Deferred Retirement Date shall be entitled to a monthly Retirement Income in the normal form or any optional form made
available under Article 7 of the Plan, commencing on the first day of the calendar month next following his Deferred Retirement Date (or such earlier date as may be required by Section 5.4). Such a Participant’s Benefit Base shall be computed as in Section 6.1 except his Deferred Retirement Date shall be substituted for his Normal Retirement Date in such computation.

6.5. Minimum Benefit Base

In no event shall a Participant’s Benefit Base at his Normal Retirement Date be less than the benefit the Participant would have received if the Participant had duly elected an Early Retirement Date.

6.6. Reemployment

If a retired or terminated Participant is restored to service and becomes an Employee or an employee of an Affiliate, the payment of Retirement Income shall be suspended in accordance with Section 203(a)(3)(B) of ERISA, and shall resume upon his subsequent retirement or other termination in accordance with Section 6.7.

6.7. Commencement of Retirement Income After Suspension of Benefits

Upon the commencement of a Participant’s Retirement Income that has been suspended under Section 6.4(a) or Section 6.6, his Benefit Base shall be computed or recomputed as in Section 6.1, except that if such a Participant retires on an Early Retirement Date, his Benefit Base shall be computed according to Section 6.3, and if such a Participant retires on a Deferred Retirement Date, his Benefit Base shall be computed according to Section 6.4. Such a Participant’s Benefit Base shall be reduced (but not below the Participant’s Benefit Base for the Plan Year preceding the year in which such computation is made), by the Actuarial Equivalent of the amount of any Retirement Income distributed to such Participant by the close of the current Plan Year during any period to which Section 6.4(a) or 6.6 applies.
ARTICLE 7. AMOUNT AND FORM OF RETIREMENT INCOME

7.1. Normal Form of Retirement Income

(a) In the case of a Participant who is a legally married Participant on his Retirement Income Commencement Date, his Retirement Income shall be paid in equal monthly installments in the form of an annuity for the life of the Participant with a survivor annuity for the life of the spouse to whom he was married on such date. This joint and survivor annuity shall be a reduced amount which is the Actuarial Equivalent of the Participant’s Benefit Base and the monthly survivor annuity shall be one-half of the amount of the monthly annuity payment for the life of the Participant. The survivor annuity payable under this Section 7.1(a) shall not be payable if the Participant dies prior to his Retirement Income Commencement Date, but shall be payable in accordance with Section 9.2. A legally married Participant may, at any time prior to his Retirement Income Commencement Date, elect not to have his Retirement Income payable in the above described joint and survivor annuity form and in lieu thereof: (i) elect to have his Retirement Income paid in the form described in Section 7.1(b), or (ii) subject to the provisions of Sections 7.2, 7.3 and 7.4, elect one of the optional annuity forms described therein. Notwithstanding the foregoing provisions of this Section 7.1(a), such election shall be effective only if made in accordance with the procedures and requirements set forth in Section 7.5.

(b) In the case of a Participant who is not a legally married Participant, his Retirement Income shall be paid in the form of an annuity for the life of the Participant in equal monthly installments each of which is equal to his Benefit Base. A Participant may, at any time prior to his Retirement Income Commencement Date, elect not to have his Retirement income payable in the above described life annuity form and in lieu thereof: (i) elect to have his Retirement Income paid in the form described in Section 7.1(b), or (ii) subject to the provisions of Sections 7.2, 7.3 and 7.4, elect one of the optional forms described therein.

7.2. Optional Joint and Survivor Annuity

(a) In lieu of the normal form of Retirement Income provided under Section 7.1, a Participant may elect an optional joint and survivor annuity which is the Actuarial Equivalent of a Participant’s Benefit Base determined in accordance with Section 6.1. Under this optional form of Retirement Income, a Participant’s benefit shall be paid in equal monthly installments in the form of an annuity for the life of the Participant with a survivor annuity for the life of his Joint Annuitant. The amount of the monthly annuity payment to a surviving Joint Annuitant shall be all, 75%, 66-2/3% or 50%, as designated by the Participant, of the monthly Retirement Income payment to the Participant. Subject to the provisions of Section 7.5, under this optional joint and survivor annuity, a Participant may designate a person other than his spouse as his Joint Annuitant.

(b) The designated percentage of the monthly Retirement Income of a Participant which is to be paid to his surviving Joint Annuitant shall not exceed 100 percent and, if the Joint-
Annuitant is a person other than the Participant’s spouse, the designated percentage of the Participant’s Retirement Income to be continued to his surviving Joint Annuitant shall be adjusted, if necessary, to provide a Retirement Income to the Participant that meets the minimum distribution benefit requirements under Section 401(a)(9) of the Code and the regulations thereunder.

(c) If either the Participant or his Joint Annuitant dies before the Participant’s Retirement Income Commencement Date, the election shall become null and void.

(d) Any election of an optional joint and survivor annuity shall become effective at a Participant’s Retirement Income Commencement Date and shall be subject to the following conditions:

(1) The election shall be made on a form prescribed by the Committee Plan Administrator.

(2) At the time a Participant elects this optional form of Retirement Income he shall name a Joint Annuitant to receive any Retirement Income payable under this Section 7.2 in the event of his death and shall furnish the Committee Plan Administrator with satisfactory proof of the age of such Joint Annuitant.

(3) The election must be made prior to the Participant’s Retirement Income Commencement Date.

(4) A Participant may elect to cancel any election of an optional joint and survivor annuity at any time prior to his Retirement Income Commencement Date.

7.3. Life Annuity 10 Years Certain Option

(a) Under this optional form of Retirement Income, a Participant’s benefit shall be paid in equal monthly installments in the form of an annuity for life on a 10-year certain basis under which the payments shall cease with the last monthly payment before his death or the end of the 10-year certain period, whichever is later. Such annuity shall be a reduced monthly amount and shall be the Actuarial Equivalent of the Participant’s Benefit Base. Payments will be made to the Participant, while living, and after his death, any payments becoming due will be made to the Participant’s designated Beneficiary. The certain period is a 10-year period beginning at the Participant’s Retirement Income Commencement Date.

(b) If a Participant dies before his Retirement Income Commencement Date, the election shall become null and void.
(c) Subject to the provisions of Section 7.5, at the time the Participant elects this optional form of Retirement Income, he shall name a Beneficiary to receive any payments becoming due after his death.

(d) Any other provision of this Section 7.3 to the contrary notwithstanding, no benefit will be permitted under Section 7.3 if payments would be made beyond the life expectancy of the Participant or over a period extending beyond the life expectancy of the Participant and his Beneficiary, or if payments would fail to meet the minimum distribution requirements under Section 401(a)(9) of the Code and the regulations thereunder.

7.4. Level Income Benefit Option

(a) Subject to the provisions of Section 7.5, a Participant who retires prior to the time when he is first eligible for Social Security payments may elect, prior to his Retirement Income Commencement Date, to have his Retirement Income payments adjusted, on an Actuarially Equivalent basis, so that, insofar as is practicable, his monthly income from the Plan and Social Security combined, both before and after commencement of his Social Security payments, will be a level amount. The maximum benefit limitations of Article 11 shall be applied prior to, and not subsequent to, such adjustment.

(b) Retirement Income payment under this option shall cease with the last payment due prior to the death of the Participant.

7.5. Explanation and Election

A Participant shall be furnished with an election form and a description of the normal and optional benefit forms, which. Such description shall include (a) written explanation of the terms and conditions of such benefit forms; a Qualified Joint and Survivor Annuity; (b) the general Participant's right to make and the effect of making an election to waive the Qualified Joint and Survivor Annuity form of benefit; (c) the rights of a Participant's spouse; (d) the right to make and the effect of making a revocation of a previous election to waive the Qualified Joint and Survivor Annuity; and (e) the relative values of the various optional forms of benefit under the plan as provided in Treasury Regulations section 1.417(a)-3. The Committee Plan Administrator shall provide such written explanation no less than 30 days and no more than 180 days prior to the Participant's Retirement Income Commencement Date or at such times as required by any applicable regulations as currently in effect. A Participant may request in writing that the Committee Plan Administrator provide additional information. The Committee Plan Administrator shall furnish the Participant with the additional information within 30 days of the Participant’s request. Any election must be received by the Committee Plan Administrator prior to the Retirement Income Commencement Date, but a Participant shall have a period of 90 days from the date on which the requested additional information is furnished to him within which to make his election. If a Participant requests additional information, Retirement Income payments will not commence until the expiration of a
90-day period from the date on which the Committee furnished such additional information to the Participant, at which time payments will commence in accordance with the Participant’s election or the normal form under Section 7.1, whichever is applicable. Any election with respect to a joint and survivor annuity under Section 7.1(a) may be revoked in writing during the period prior to the commencement of benefit payments, and additional elections and revocations may be made during that period.

Notwithstanding any of the foregoing provisions of this Article 7, if the Participant is legally married and his election or revocation of an election of a benefit designates a Joint Annuitant or Beneficiary other than his surviving spouse or elects an optional form of Retirement Income that provides a survivor benefit that is less than 50 percent, such election or revocation shall be effective only by filing with the Committee, together with such election or revocation, the written consent of the Participant’s spouse, which consent acknowledges the effect of such election or revocation and is witnessed by a Plan representative or notary public. A waiver of the joint and survivor annuity under Section 7.1(a) shall be effective on and after the date a waiver form is completed, together with such spousal consent, and filed with the Committee.

Spousal consent of an election, revocation or waiver of a benefit shall not be required if there is no spouse or the spouse cannot reasonably be located.

The consent of the Participant and the Participant's spouse under this section shall be obtained in writing within the 180-day period ending on the Retirement Income Commencement Date.
ARTICLE 8. EMPLOYEE CONTRIBUTIONS

8.1 No Employee Contributions

In no event shall a Participant make contributions to the Plan.
ARTICLE 9. PRE-RETIREMENT SPOUSE’S DEATH BENEFIT

9.1. Death Benefits Provided

There are no death benefits under the Plan, except as provided in Article 7 or Article 10 and Section 9.2.

9.2. Pre-Retirement Spouse’s Death Benefit

(a) In the event of the death of a Participant, or an inactive Participant, who has completed 3 years of Vesting Service and dies prior to his Retirement Income Commencement Date, his surviving spouse (if any) shall be entitled to monthly payments under the Plan for her lifetime, beginning as of the first day of the calendar month next following the date that would have been the deceased Participant’s Normal Retirement Date. Such payments shall be in the same amount as the spouse would have received after the Participant’s subsequent death if he had not died at his actual date of death but instead had:

(1) separated from service on the earlier of the date of his death or his actual separation from service;

(2) survived to his Normal Retirement Date;

(3) retired on his Normal Retirement Date, with the same Final Average Monthly Earnings and years of Benefit Service as of his date of death;

(4) elected the normal form of benefit under Section 7.1(a) of the Plan; and

(5) then died immediately thereafter.

(b) The surviving spouse may elect, by written request to the Committee Administrator, to have such payments commence at an earlier date, provided that payments shall not commence before the date the deceased Participant would have attained the earliest retirement age under the Plan. Such payments shall be in the same amount as the surviving spouse would have received after the Participant’s death if he had not died at his actual date of death but instead had:

(1) separated from service on the earlier of his date of death or his actual separation from service;

(2) survived to the earliest retirement age under the Plan;
(3) retired at the earliest retirement age under the Plan, with the same Final Average Monthly Earnings and years of Benefit Service as of his date of death;

(4) elected the normal form of benefit under Section 7.1(a) of the Plan; and

(5) then died immediately thereafter.

For purposes of this Section 9.2, a Participant’s earliest retirement age under the Plan is the earliest age at which the Participant would have been eligible for retirement under Section 5.1 or 5.2, based on the years of Vesting Service he has completed at the date of his death. Except as provided in Section 9.2(c), if Section 5.2 is applicable, then the applicable reduction for early commencement of Retirement Income in accordance with Section 6.3 shall apply in determining the amount of the pre-retirement spouse’s death benefit.

(c) Notwithstanding the foregoing provisions of Section 9.2(b) above, if a Participant dies prior to his Retirement Income Commencement Date, but on or after becoming eligible for early retirement under Section 5.2 and his surviving spouse elects to receive the pre-retirement spouse’s death benefit before such Participant would have attained age 65, the applicable reduction for early commencement of Retirement Income in accordance with Section 6.3 will not apply in case of such surviving spouse.

(d) The pre-retirement spouse’s death benefit may not be waived (or another Beneficiary selected). The Plan fully subsidizes the costs of such benefit.

9.3. Death While Performing Qualified Military Service. In the case of a death occurring on or after January 1, 2007, if a Participant dies while performing qualified military service (as defined in Code Section 414(u)), the survivors of the Participant are entitled to any additional benefits (other than benefit accruals relating to the period of qualified military service) provided under the Plan as if the Participant had resumed employment and then terminated employment on account of death.
ARTICLE 10. TERMINATION OF EMPLOYMENT

10.1. Vested Benefit

A Participant whose employment by the Company and any Affiliate terminates (other than by death or retirement) shall, if he has then completed the requisite number of years of Vesting Service to be vested, be entitled to a monthly Retirement Income in the normal form or any optional form made available under Article 7 of the Plan, commencing on the first day of the calendar month next following his Normal Retirement Date. Such a Participant’s Benefit Base shall be computed as in Section 6.1, and the normal or optional form of his Retirement Income shall be the Actuarial Equivalent of his Benefit Base so computed.

For Participants whose Employment Commencement Date is prior to January 1, 2014, the requisite number of years of Vested Service to be vested shall be three (3). For Participants whose Employment Commencement Date is after December 31, 2013, the requisite number of years of Vested Service to be vested shall be five (5).

In lieu of the Retirement Income specified above, upon 30 days prior written notice to the Company, such a Participant may elect to receive a reduced Retirement Income commencing on the first day of any month within the 10 years immediately preceding the first day of the calendar month next following his Normal Retirement Date. Such reduced Retirement Income shall be equal to such Participant’s Benefit Base computed as in Section 6.1, but reduced by 1/12 of 7 percent for each of the first 60 months and 1/12 of 6 percent for each additional month by which the Participant’s Retirement Income Commencement Date precedes the first day of the calendar month next following the Participant’s Normal Retirement Date, and the normal or optional form of his Retirement Income shall be the Actuarial Equivalent of his Benefit Base so computed.

10.2. Transfer

A Participant who becomes an inactive Participant pursuant to Section 4.3 because his employment with the Company terminates as a result of transfer to an Affiliate shall, as of such date, have his Final Average Monthly Earnings frozen and he shall cease to accrue years of Benefit Service, unless and until such time as he shall again be an Employee of the Company.

10.3. Non-Vested Terminated Participant

Except as provided in Section 10.1, there shall be no benefits payable under the Plan on account of the termination of employment of a Participant from the Company and any Affiliate. If a Participant terminates his employment for any reason other than retirement under the Plan, and has not completed 3 years of Vesting Service (5 years of Vesting Service for Participant’s whose Employment Commencement date is after December 31, 2013) prior to his termination, such that the present value of the Participant’s nonforfeitable accrued benefit is $0, then he shall
be deemed to have received a full distribution of such nonforfeitable accrued benefit upon his termination.
ARTICLE 11. REQUIRED PROVISIONS/MAXIMUM BENEFITS

11.1. Limitation on Benefits

(a) Any other provisions of the Plan to the contrary notwithstanding, subject to the provisions of Sections 11.2 and 11.3, a Participant’s annual Retirement Income attributable to the Company or any Affiliate provided to the Participant under any other defined benefit plan, shall be equal to the lesser of: (i) $160,000, as adjusted under Section 415(d) of the Code (“dollar limitation”) or (ii) 100 percent of such Participant’s average annual 415 Compensation during the three consecutive years of his Benefit Service affording the highest such average, or during all of the years of such Benefit Service if less than three years (“earnings limitation”); provided that if the Participant has not completed 10 years of participation, the maximum dollar limitation shall be reduced by the ratio in which the number of years of such Participant’s participation bears to 10, and that such reduction shall be applied separately with respect to each change in the benefit structure of the Plan to the extent required by regulations under Section 415(b)(5) of the Code; provided further that if the Participant has not completed 10 years of Vesting Service, the maximum earnings limitation shall be reduced in the ratio which the number of years of such Participant’s Vesting Service bears to 10. (For purposes of this Article 11, 50 percent shall be substituted for 80 percent in the definition of an Affiliate.)

A limitation as adjusted under Section 415(d) of the Code will apply to limitation years ending with or within the calendar year for which the adjustment applies.

A participant who is permanently and totally disabled within the meaning of Code section 415(c)(3)(C)(i) shall be credited with a year of participation for purposes of this section 11.1(a).

(b) If the Participant’s Retirement Income is payable in a form other than the normal form as described in Section 7.1(a), the Retirement Income for that form of payment shall be adjusted to an actuarially equivalent straight life annuity before the application of the maximum limitation, and, so modified, shall be subject to the limitation. For a benefit paid in a form to which section 417(e)(3) does not apply, the actuarially equivalent straight life annuity benefit is the greater of— (i) The annual amount of the straight life annuity (if any) payable to the participant under the plan commencing at the same annuity starting date as the form of benefit payable to the participant; or (ii) The annual amount of the straight life annuity commencing at the same annuity starting date that has the same actuarial present value as the form of benefit payable to the participant, computed using a 5 percent interest assumption and the applicable mortality table described in §1.417(e)-1(d)(2) for that annuity starting date. Except as otherwise provided below, for a benefit paid in a form to which section 417(e)(3) applies, the actuarially equivalent straight life annuity benefit is the greatest of: (A) The annual amount of the straight life annuity commencing at the annuity starting date that has the same actuarial present value as the particular form of benefit payable, computed using the interest rate and mortality table, or tabular factor, specified in the plan for actuarial equivalence; (B) The annual amount of the...
straight life annuity commencing at the annuity starting date that has the same actuarial present value as the particular form of benefit payable, computed using a 5.5 percent interest assumption and the applicable mortality table for the distribution under §1.417(e)-1(d)(2); or (C) The annual amount of the straight life annuity commencing at the annuity starting date that has the same actuarial present value as the particular form of benefit payable (computed using the applicable interest rate for the distribution under §1.417(e)-1(d)(3) and the applicable mortality table for the distribution under §1.417(e)-1(d)(2)), divided by 1.05. However, for a distribution to which section 417(e)(3) applies and which has an annuity starting date occurring in plan years beginning in 2004 or 2005, except as provided in section 101(d)(3) of the Pension Funding Equity Act of 2004, Public Law 108-218 (118 Stat. 596), the actuarially equivalent straight life annuity benefit is the greater of— (A) The annual amount of the straight life annuity commencing at the annuity starting date that has the same actuarial present value as the particular form of benefit payable, computed using the interest rate and mortality table, or tabular factor, specified in the plan for actuarial equivalence; or (B) The annual amount of the straight life annuity commencing at the annuity starting date that has the same actuarial present value as the particular form of benefit payable, computed using a 5.5 percent interest assumption and the applicable mortality table for the distribution under §1.417(e)-1(d)(2). For purposes of the adjustments described in this paragraph (c), the following benefits are not taken into account: (A) Survivor benefits payable to a surviving spouse under a qualified joint and survivor annuity (as defined in section 417(b)) to the extent that such benefits would not be payable if the participant's benefit were not paid in the form of a qualified joint and survivor annuity. (B) Ancillary benefits that are not directly related to retirement benefits, such as preretirement disability benefits not in excess of the qualified disability benefit, preretirement incidental death benefits (including a qualified preretirement survivor annuity), and post-retirement medical benefits.

(c) For a distribution with an annuity starting date that occurs before the participant attains the age of 62, the age-adjusted section 415(b)(1)(A) dollar limit generally is determined as the actuarial equivalent of the annual amount of a straight life annuity commencing at the annuity starting date that has the same actuarial present value as a deferred straight life annuity commencing at age 62, where annual payments under the straight life annuity commencing at age 62 are equal to the dollar limitation of section 415(b)(1)(A) (as adjusted pursuant to section 415(d) and §1.415(d)-1 for the limitation year), and where the actuarially equivalent straight life annuity is computed using a 5 percent interest rate and the applicable mortality table under §1.417(e)-1(d)(2) that is effective for that annuity starting date (and expressing the participant's age based on completed calendar months as of the annuity starting date). However, if the plan has an immediately commencing straight life annuity payable both at age 62 and the age of benefit commencement, then the age-adjusted section 415(b)(1)(A) dollar limit is equal to the lesser of— (A) The limit determined as set forth above and (B) The amount determined by multiplying the section 415(b)(1)(A) dollar limit (as adjusted pursuant to section 415(d) and §1.415(d)-1 for the limitation year) by the ratio of the annual amount of the immediately commencing straight life annuity under the plan to the annual amount of the straight life annuity under the plan commencing at age 62, with both annual amounts determined without applying the rules of section 415. For purposes of determining the 415 maximum, any decrease in the defined benefit
dollar limitation determined in accordance with this paragraph shall not reflect a mortality decrement if benefits are not forfeited upon the death of the Participant. If any benefits are forfeited upon death, the full mortality decrement is taken into account.

If the benefit of a Participant begins after the Participant attains age 65, the age-adjusted section 415(b)(1)(A) dollar limit generally is determined as the actuarial equivalent of the annual amount of a straight life annuity commencing at the annuity starting date that has the same actuarial present value as a straight life annuity commencing at age 65, where annual payments under the straight life annuity commencing at age 65 are equal to the dollar limitation of section 415(b)(1)(A) (as adjusted pursuant to section 415(d) and §1.415(d)-1 for the limitation year), and where the actuarially equivalent straight life annuity is computed using a 5 percent interest rate and the applicable mortality table under §1.417(e)-1(d)(2) that is effective for that annuity starting date (and expressing the participant's age based on completed calendar months as of the annuity starting date). However, if the plan has an immediately commencing straight life annuity payable as of the annuity starting date and an immediately commencing straight life annuity payable at age 65, then the age-adjusted section 415(b)(1)(A) dollar limit is equal to the lesser of—(A) The limit as otherwise determined above, and (B) The amount which is equal to the section 415(b)(1)(A) dollar limit (as adjusted pursuant to section 415(d) and §1.415(d)-1 for the limitation year) multiplied by the ratio of the annual amount of the adjusted immediately commencing straight life annuity under the plan to the adjusted age 65 straight life annuity. The adjusted immediately commencing straight life annuity is the annual amount of the immediately commencing straight life annuity payable to the participant, computed disregarding the participant's accruals after age 65 but including actuarial adjustments even if those actuarial adjustments are applied to offset accruals. For this purpose, the annual amount of the immediately commencing straight life annuity is determined without applying the rules of section 415. The adjusted age 65 straight life annuity is the annual amount of the straight life annuity that would be payable under the plan to a hypothetical participant who is 65 years old and has the same accrued benefit (with no actuarial increases for commencement after age 65) as the participant receiving the distribution (determined disregarding the participant's accruals after age 65 and without applying the rules of section 415). For these purposes, mortality between age 65 and the age at which benefits commence shall be ignored.

(d) (i) For purposes of this Article and also for purposes of determining whether the Plan is “Top-heavy” pursuant to Article 18 of the Plan, “415 Compensation” shall mean compensation within the meaning of section 415(c)(3) of the Code actually paid or made available to an Employee (or, if earlier, includible in the gross income of the Employee) within the Limitation Year. For this purpose, compensation is treated as paid on a date if it is actually paid on that date or it would have been paid on that date but for an election under Section 401(k), 403(b), 408(k), 408(p)(2)(A)(i), 457(b), 132(f), or 125 of the Code. 415 Compensation shall include amounts that are includible in the gross income of an Employee under the rules of section
409A or section 457(f)(1)(A) of the Code or because the amounts are constructively received by the Employee.

(ii) 415 Compensation shall not reflect compensation for a year that is in excess of the limitation of section 401(a)(17) of the Code that applies to that year. The Plan will not be treated as failing to satisfy this subparagraph (ii) merely because, under provisions of the Plan adopted and in effect before April 5, 2007, the Plan's definition of Compensation used for purposes of the limitations of section 415(b)(1)(B) of the Code reflects compensation for a year in excess of the limitation of section 401(a)(17) of the Code that applies to that year.)

(iii) Payment prior to Severance from Employment. In order to be taken into account for a Limitation Year, compensation within the meaning of section 415(c)(3) of the Code must be paid or treated as paid to the Employee prior to Severance from Employment (within the meaning of section 401(k)(2)(B)(i)(I) of the Code) with the Employer maintaining the Plan; provided, however, that compensation does not fail to be compensation (within the meaning of section 415(c)(3) of the Code) merely because it is paid after the Employee's severance from employment with the Employer, provided the compensation is paid by the later of 2-1/2 months after severance from employment with the Employer or the end of the Limitation Year that includes the date of severance from employment with the Employer, subject to the following rules:

(A) 415 Compensation (but not necessarily Earnings for benefit calculation purposes) includes amounts paid within such 2 ½ months for regular compensation for services during the Employee's regular working hours, or compensation for services outside the Employee's regular working hours (such as overtime or shift differential), commissions, bonuses, or other similar payments, provided that such payments would have been paid to the Employee prior to a severance from employment if the Employee had continued in employment with the Employer.

(B) 415 Compensation (but not necessarily Earnings for benefit calculation purposes) includes payment within such 2 ½ months for unused accrued bona fide sick, vacation, or other leave, but only if the Employee would have been able to use the leave if employment had continued, and amounts received by an Employee pursuant to a nonqualified unfunded deferred compensation plan, but only if the payment would have been paid to the Employee at the same time if the Employee had continued in employment with the Employer and only to the extent that the payment is includible in the Employee's gross income.

(C) Other post-severance payments. Any post-severance payment that is not described in (A) or (B) above is not considered 415 Compensation even if it is paid within the 2 ½ month period after severance from employment. Thus, compensation does not include severance pay, or parachute payments within the meaning of section 280G(b)(2) of the Code, if they are paid after severance from employment with the Employer, and does not include post-severance payments under a nonqualified unfunded deferred compensation plan unless the payments would have been
paid at that time without regard to the severance from employment.

(iv) Effective for wages paid after December 31, 2008, Differential Wages Payments paid to an individual in active Qualified Military Service will be treated as wages for purposes of section 415 of the Code, but shall not be treated as Earnings for purposes of calculating a Participant’s retirement benefit under the Plan.

(A) Differential Wage Payment. For purposes of this Subsection, the term “Differential Wage Payment” means any payment which:

1. is made by an Employer to an individual with respect to any period during which the individual is performing service in the uniformed services (as defined in chapter 43 of title 38, United States Code) while on active duty for a period of more than 30 days; and
2. represents all or a portion of the wages the individual would have received from the Employer if the individual were performing services for the Employer.

(B) Treatment of Differential Wage Payments. For the purpose of the Plan:

1. an individual receiving a Differential Wage Payment shall be treated as an Employee of the Employer making the payment;
2. the Differential Wage Payment shall be treated as Compensation; and

(C) the Plan shall not be treated as failing to meet the requirements of any plan qualification requirements under Code section 401(a) where a contribution or benefit is based on the Differential Wage Payment.

(f) Determination of annual benefit in the case of multiple annuity starting dates. If a Participant has or will have distributions commencing at more than one annuity starting date, then the limitations of section 415 must be satisfied as of each of the annuity starting dates, taking into account the benefits that have been or will be provided at all of the annuity starting dates. This will happen, for example, where benefit distributions to a participant have previously commenced under a plan that is aggregated for purposes of section 415 with a plan under which the participant receives current accruals. In determining the annual benefit for such a participant as of a particular annuity starting date, the plan shall actuarially adjust the past and future distributions with respect to the benefits that commenced at the other annuity starting dates. These adjustments must be made using the rules of §1.415(b)-2.

(g) For purposes of applying this Article 11, all defined benefit plans of the Company and any Affiliate, including the Plan, shall be combined or aggregated.
11.2. Benefit Restrictions.

(a) Effective Date and Application of Section

(1) Effective Date. The provisions of this Section apply to Plan Years beginning after December 31, 2007.

(2) This Section only applies to single employer plans (a plan that is not a multiemployer plan within the meaning of Code Section 414(f)) and does not apply to a plan maintained pursuant to one or more collective bargaining agreements between employee representatives and one or more employers. Furthermore, this Section shall not apply to for the first five (5) Plan Years of the Plan. For purposes of this subsection, the term Plan shall include any predecessor plan.

(3) Notwithstanding anything in this Section to the contrary, the provision of Code Section 436 and the Regulations thereunder are incorporated herein by reference.

(4) For Plans that have a valuation date other than the first day of the Plan Year, the provisions of Code Section 436 and this Article will be applied in accordance with Regulations.

(b) Funding-Based Limitation on Shutdown Benefits and Other Unpredictable Contingent Event Benefits

(1) In general. If a Participant is entitled to an "unpredictable contingent event benefit" payable with respect to any event occurring during any Plan Year, then such benefit may not be provided if the "adjusted funding target attainment percentage" for such Plan Year (A) is less than sixty percent (60%) or, (B) would be less than sixty percent (60%) taking into account such occurrence.

(2) Exemption. Paragraph (1) shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year, upon payment by the Employer of a contribution (in addition to any minimum required contribution under Code Section 430) equal to:

(A) in the case of (b)(1)(A) above, the amount of the increase in the funding target of the Plan (under Code Section 430) for the Plan Year attributable to the occurrence referred to in paragraph (1), and

(B) in the case of (b)(1)(B) above, the amount sufficient to result in an "adjusted funding target attainment percentage" of sixty percent (60%).
(3) Unpredictable contingent event benefit. For purposes of this subsection, the term "unpredictable contingent event benefit" means any benefit payable solely by reason of: (A) a plant shutdown (or similar event, as determined by the Secretary of the Treasury), or (B) an event other than the attainment of any age, performance of any service, receipt or derivation of any compensation, or occurrence of death or disability.

(c) Limitations on Plan Amendments Increasing Liability for Benefits

(1) In general. No amendment which has the effect of increasing liabilities of the Plan by reason of increases in benefits, establishment of new benefits, changing the rate of benefit accrual, or changing the rate at which benefits become nonforfeitable may take effect during any Plan Year if the "adjusted funding target attainment percentage" for such Plan Year is: (A) less than eighty percent (80%), or (B) would be less than eighty percent (80%) taking into account such amendment.

(2) Exemption. Paragraph (c)(1) above shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year (or if later, the effective date of the amendment), upon payment by the Employer of a contribution (in addition to any minimum required contribution under Code Section 430) equal to:

(A) in the case of paragraph (c)(1)(A) above, the amount of the increase in the funding target of the Plan (under Code Section 430) for the Plan Year attributable to the amendment, and

(B) in the case of paragraph (c)(1)(B) above, the amount sufficient to result in an "adjusted funding target attainment percentage" of eighty percent (80%).

(3) Exception for certain benefit increases. Paragraph (1) shall not apply to any amendment which provides for an increase in benefits under a formula which is not based on a Participant's compensation, but only if the rate of such increase is not in excess of the contemporaneous rate of increase in average wages of Participants covered by the amendment.

(d) Limitations on Accelerated Benefit Distributions

(1) Funding percentage less than sixty percent (60%). If the Plan's "adjusted funding target attainment percentage" for a Plan Year is less than sixty percent (60%), then the Plan may not pay any "prohibited payment" after the valuation date for the Plan Year.

(2) Bankruptcy. During any period in which the Employer is a debtor in a case under Title 11, United States Code, or similar Federal or State law, the Plan may not pay any "prohibited payment." The preceding sentence shall not apply on or after the date on which the
enrolled actuary of the Plan certifies that the "adjusted funding target attainment percentage" of the Plan is not less than one hundred percent (100%).

(3) Limited payment if percentage at least sixty percent (60%) but less than eighty percent (80%).

(A) In general. If the Plan's "adjusted funding target attainment percentage" for a Plan Year is sixty percent (60%) or greater but less than eighty percent (80%), then the Plan may not pay any "prohibited payment" after the valuation date for the Plan Year to the extent the amount of the payment exceeds the lesser of:

(i) fifty (50) percent of the amount of the payment which could be made without regard to this subsection, or

(ii) the present value (determined under guidance prescribed by the Pension Benefit Guaranty Corporation, using the interest and mortality assumptions under Code Section 417(e)) of the maximum guarantee with respect to the participant under ERISA Section 4022.

(B) One-time application.

(i) In general. Only one "prohibited payment" meeting the requirements of subparagraph (A) may be made with respect to any Participant during any period of consecutive Plan Years to which the limitations under either paragraph (1) or (2) or this paragraph applies.

(ii) Treatment of beneficiaries. For purposes of this subparagraph, a Participant and any Beneficiary (including an alternate payee, as defined in Code Section 414(p)(8)) shall be treated as one Participant. If the Accrued Benefit of a Participant is allocated to such an alternate payee and one or more other persons, the amount under subparagraph (A) shall be allocated among such persons in the same manner as the Accrued Benefit is allocated unless the qualified domestic relations order (as defined in Code Section 414(p)(1)(A)) provides otherwise.

(4) Exception. This subsection shall not apply for any Plan Year if the terms of the Plan (as in effect for the period beginning on September 1, 2005, and ending with such Plan Year) provide for no benefit accruals with respect to any Participant during such period.

(5) "Prohibited payment." For purposes of this subsection, the term "prohibited payment" means:
(A) any payment, in excess of the monthly amount paid under a single life annuity (plus any Social Security supplements described in the last sentence of Code Section 411(a)(9)), to a Participant or Beneficiary whose Annuity Starting Date occurs during any period a limitation under paragraph (1) or (2) is in effect.

(B) any payment for the purchase of an irrevocable commitment from an insurer to pay benefits, and

(C) any other payment specified by the Secretary by Regulations.

Such term shall not include the payment of a benefit which under Code Section 411(a)(11) may be immediately distributed without the consent of the Participant.

(e) Limitation on Benefit Accruals for Plans with Severe Funding Shortfalls

(1) In general. If the Plan's "adjusted funding target attainment percentage" for a Plan Year is less than sixty percent (60%), benefit accruals under the Plan shall cease as of the valuation date for the Plan Year.

(2) Exemption. Paragraph (1) shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year, upon payment by the Employer of a contribution (in addition to any minimum required contribution under Code Section 430) equal to the amount sufficient to result in an "adjusted funding target attainment percentage" of sixty percent (60%)

(f) Rules Relating to Contributions Required to Avoid Benefit Limitations

(1) Security may be provided.

(A) In general. For purposes of this section, the "adjusted funding target attainment percentage" shall be determined by treating as an asset of the Plan any security provided by the Employer in a form meeting the requirements of subparagraph (B).

(B) Form of security. The security required under subparagraph (A) shall consist of (i) a bond issued by a corporate surety company that is an acceptable surety for purposes of ERISA Section 412, (ii) cash, or United States obligations which mature in three (3) years or less, held in escrow by a bank or similar financial institution, or (iii) such other form of security as is satisfactory to the Secretary and the parties involved.
(C) Enforcement. Any security provided under subparagraph (A) may be perfected and enforced at any time after the earlier of:

(i) the date on which the Plan terminates,

(ii) if there is a failure to make a payment of the minimum required contribution for any Plan Year beginning after the security is provided, the due date for the payment under section 430(j), or

(iii) if the "adjusted funding target attainment percentage" is less than sixty percent (60%) for a consecutive period of 7 years, the valuation date for the last year in the period.

(D) Release of security. The security shall be released (and any amounts thereunder shall be refunded together with any interest accrued thereon) at such time as the Secretary may prescribe in Regulations, including Regulations for partial releases of the security by reason of increases in the "adjusted funding target attainment percentage."

(2) Prefunding balance or funding standard carryover balance may not be used. No prefunding balance or funding standard carryover balance under Code Section 430(f) may be used under subsection (b), (c), or (e) to satisfy any payment an Employer may make under any such subsection to avoid or terminate the application of any limitation under such subsection.

(3) Deemed reduction of funding balances:

(A) In general. In any case in which a benefit limitation under subsection (d) would (but for this subparagraph) apply to such Plan for the Plan Year, the Employer shall be treated for purposes of this title as having made an election under Code Section 430(f) to reduce the prefunding balance or funding standard carryover balance by such amount as is necessary for such benefit limitation to not apply to the Plan for such Plan Year.

(B) Exception for insufficient funding balances. Subparagraph (A) shall not apply with respect to a benefit limitation for any Plan Year if the application of subparagraph (A) would not result in the benefit limitation not applying for such Plan Year.

(g) Presumed Underfunding for Purposes of Benefit Limitations

(1) Presumption of continued underfunding. In any case in which a benefit limitation under subsection (b), (c), (d), or (e) has been applied to a Plan with respect to the Plan Year preceding the current Plan Year, the "adjusted funding target attainment percentage" of the Plan for the current Plan Year shall be presumed to be equal to the "adjusted funding target
attainment percentage" of the Plan for the preceding Plan Year until the enrolled actuary of the Plan certifies the actual "adjusted funding target attainment percentage" of the Plan for the current Plan Year.

(2) Presumption of underfunding after 10th month. In any case in which no certification of the "adjusted funding target attainment percentage" for the current Plan Year is made with respect to the Plan before the first day of the 10th month of such year, for purposes of subsections (b), (c), (d), and (e), such first day shall be deemed, for purposes of such subsection, to be the valuation date of the Plan for the current Plan Year and the Plan's "adjusted funding target attainment percentage" shall be conclusively presumed to be less than sixty percent (60%) as of such first day.

(3) Presumption of underfunding after 4th month for nearly underfunded plans. In any case in which:

(A) a benefit limitation under subsection (b), (c), (d), or (e) did not apply to a Plan with respect to the Plan Year preceding the current Plan Year, but the "adjusted funding target attainment percentage" of the Plan for such preceding Plan Year was not more than ten (10) percentage points greater than the percentage which would have caused such subsection to apply to the Plan with respect to such preceding Plan Year, and

(B) as of the first day of the 4th month of the current Plan Year, the enrolled actuary of the Plan has not certified the actual "adjusted funding target attainment percentage" of the Plan for the current Plan Year, until the enrolled actuary so certifies, such first day shall be deemed, for purposes of such subsection, to be the valuation date of the Plan for the current Plan Year and the "adjusted funding target attainment percentage" of the Plan as of such first day shall, for purposes of such subsection, be presumed to be equal to ten (10) percentage points less than the "adjusted funding target attainment percentage" of the Plan for such preceding Plan Year.

(h) Treatment of Plan as of Close of Prohibited or Cessation Period. The following provisions apply for purposes of applying this Section.

(1) Operation of Plan after period. Payments and accruals will resume effective as of the day following the close of the period for which any limitation of payment or accrual of benefits under subsection (d) or (e) applies.

(2) Treatment of affected benefits. Nothing in this subsection shall be construed as affecting the Plan's treatment of benefits which would have been paid or accrued but for this Section.
(i) Definitions.

(1) The term "funding target attainment percentage" has the same meaning given such term by Code Section 430(d)(2), except as otherwise provided herein. However, in the case of Plan Years beginning in 2008, the "funding target attainment percentage" for the preceding Plan Year may be determined using such methods of estimation as the Secretary may provide.

(2) The term "adjusted funding target attainment percentage" means the "funding target attainment percentage" which is determined under paragraph (1) by increasing each of the amounts under subparagraphs (A) and (B) of Code Section 430(d)(2) by the aggregate amount of purchases of annuities for employees other than highly compensated employees (as defined in Code Section 414(q)) which were made by the Plan during the preceding two (2) Plan Years.

(3) Application to plans which are fully funded without regard to reductions for funding balances. In the case of a Plan for any Plan Year, if the "funding target attainment percentage" is one hundred percent (100%) or more (determined and without regard to the reduction in the value of assets under Code Section 430(f)(4)), the "funding target attainment percentage" for purposes of paragraphs (1) and (2) shall be determined without regard to such reduction.

However, the transfer of amounts from this Plan to a nonqualified foreign trust is treated as a distribution and the transfer of assets and liabilities from this Plan to a plan that satisfies Section 1165 of the Puerto Rico Code is also treated as distribution from the transferor plan.
ARTICLE 12.  FUND AND EMPLOYER CONTRIBUTIONS

12.1 Trust Agreement

The Company shall participate in the Trust Agreement with a Trustee or Trustees to be designated by the Committee who shall serve at the pleasure of the Company. The officers of the Company are authorized to act on its behalf with respect to the appointment and removal of a Trustee or Trustees. The Trust Agreement shall provide for the administration of the Fund in such form, and shall contain such provisions as the Committee may deem appropriate, including, but not by way of limitation, provisions with respect to the investment of all or any portion of the funds held pursuant to the Plan in common or preferred stocks of corporations, the authority to amend the Trust Agreement and to terminate the Trust Agreement and to settle the accounts of the Trustee on behalf of all persons having an interest in the Fund. The Company shall make contributions to the Fund at such times and in such amounts as the Committee may determine provided that, absent approval from the Board of Directors, the Committee is authorized hereunder to direct only those contributions to the Fund as may be necessary to meet the minimum funding standards prescribed by law. The Committee may retain an enrolled actuary to certify to the Committee and Company the amount necessary to provide pension benefits to the Participants under the terms of the Plan and the funding method then in effect and to meet any minimum funding standards prescribed by law.

12.2 Bank or Trust Company as Trustee

If a Trustee is a bank or trust company supervised by a state or Federal agency, (a) the assets of the Fund may be invested in, and the Trustee, in its capacity as a trustee, may purchase from or sell to such bank or trust company an interest in, a common or collective trust fund or pooled investment fund maintained by such bank or trust company; (b) the assets of the Fund may be invested in deposits which bear a reasonable rate of interest with such bank or trust company; and (c) solely for paying expenses of the Plan, assets of the Fund may be placed in a non-interest bearing checking account with such bank or trust company if such bank or trust company has adopted specific guidelines in accordance with regulations issued by the Department of Labor which would govern such deposits, however, such deposits shall at all times be kept to the minimum amount feasible.

The Company, by action of the Board of Directors, may enter into or continue a contract or contracts with an insurance company or companies to provide for payment of any of the benefits provided under the Plan, and may direct the Trustee to disburse any funds held by it in respect of such benefits in payment of premiums or any other obligations under any such contract; provided, however, that, notwithstanding any provisions of the Plan to the contrary, where benefits under the Plan are provided under a contract with an insurance company, the
payment of benefits to Participants and their Beneficiaries thereunder shall be subject to the provisions of such insurance company’s contract.

12.43 Exclusive Benefit

The principal or income of the Fund and any assets held under any contract or contracts with an insurance company or companies shall not be used for any purposes whatsoever other than for the exclusive benefit of Participants and their Beneficiaries or to meet the necessary expenses of the Plan; provided, however, that upon the Company’s request, a contribution made by mistake of fact shall be returned to the Company within one year after payment of the mistaken contribution; and provided, further, that all contributions shall be returned within one year following failure of the Plan to qualify initially pursuant to Section 17.8; and provided, further, that all contributions to the Plan are made on the condition that they are deductible, and shall be returned to the Company to the extent that such contributions are not deductible, within one year after disallowance of the deduction; and provided, further, that after all the liabilities under the Plan have been satisfied, any property remaining in the Fund or with an Insurance company shall be distributed by the Trustee or insurance company to the Company.
ARTICLE 13. INVESTMENT MANAGER

13.1.—Appointment

The Committee may appoint one or more Investment Managers to be designated by the Committee to serve at the pleasure of the Committee. In such case where an Investment Manager is appointed, the Committee will determine the portion of the assets of the Fund which are to be allocated to, or managed by, such Investment Manager.

13.2.—Responsibilities

An Investment Manager shall manage the investment and reinvestment of that portion of the assets of the Fund which have been allocated to such Investment Manager in accordance with the established funding policy. No Investment Manager shall provide, directly or indirectly, brokerage services to the Plan. An Investment Manager shall not have custody of any assets of the Fund, in its capacity as Investment Manager (such responsibility being assigned to the Trustee), and shall have no responsibility with respect to the administration and operation of the Plan, the safekeeping of the assets of the Fund or the management of assets of the Fund which have not been allocated to such Investment Manager.
ARTICLE 14. ADMINISTRATION

14.1 Records and Reports

The Company shall maintain all records required for the operation and administration of the Plan and shall have the responsibility for filing all reports or other documents required to be filed with governmental departments, agencies or bureaus and for providing information and materials to Participants and their Beneficiaries.

14.2 Authority of Committee to Administer Trust Agreement

Except with respect to the appointment and removal of a Trustee which power is reserved to the Company and its duly authorized officers or agents, the Committee shall administer the Trust Agreement in accordance with its provisions and shall have all powers necessary for such purpose, including but not limited to the power:

(a) to appoint and remove the Investment Managers;

(b) to establish investment and funding policies for the Plan;

(c) to evaluate the performance of the Investment Managers; and

(d) to employ one or more persons to render advice with respect to any of its responsibilities under the Plan and under the Trust Agreement.

With respect to all actuarial matters relating to the Plan, the decisions of the Committee, acting on the advise of an enrolled actuary, shall be final and binding.

14.3 Appointment of Committee/Plan Administrator

The Board of Directors shall appoint a Committee, which shall consist of as many members as the Chairman of the Board, which may from time to time appoint and shall serve at the pleasure of the Chairman, be a standing committee of the Board, to operate and administer the Plan. The Committee/Plan Administrator shall be the “Named Fiduciary” for purposes of ERISA section 402. If the Plan Administrator is a standing committee of the Board, the composition, officers and rules of such committee shall be governed by the Bylaws or other governing instrument of the Company. If the Plan Administrator is not a standing committee of the Board, the Plan Administrator shall consist of a different committee consisting of as many members as the Board may determine, which may be by position in the Company. The Plan Administrator committee shall have a chairman who shall be appointed from time to time by the Chairman of the Board from the members of the Committee/such committee. The Plan Administrator Committee shall appoint a secretary who may be, but need not be, a member.
of the Committee. The Committee Plan Administrator shall discharge its duties for the exclusive benefit of Participants and their Beneficiaries.

14.4.13.3 Rules and Regulations

The Committee Plan Administrator may adopt such rules and regulations as it may deem desirable or necessary for the administration of the Plan on a consistent and nondiscriminatory basis. All actions of the Committee Plan Administrator shall be taken with the concurrence of a majority of its members, either at a meeting or in writing without a meeting. Written records shall be kept of meetings and actions of the Committee Plan Administrator. No member of the Committee Plan Administrator committee shall act on any matter under the Plan in which he alone is personally interested.

13.4 Authority of Plan Administrator to Administer Trust Agreement

Except with respect to the appointment and removal of a Trustee which power is reserved to the Company and its duly authorized officers or agents, the Plan Administrator shall administer the Trust Agreement in accordance with its provisions and shall have all powers necessary for such purpose, including but not limited to the power:

(a) to appoint and remove the Investment Managers;

(b) to establish investment and funding policies for the Plan;

(c) to evaluate the performance of the Investment Managers; and

(d) to employ one or more persons to render advice with respect to any of its responsibilities under the Plan and under the Trust Agreement.

14 With respect to all actuarial matters relating to the Plan, the decisions of the Plan Administrator, acting on the advice of an enrolled actuary, shall be final and binding.

13.5 Administration by the Committee Plan Administrator

The Committee Plan Administrator shall administer the Plan in accordance with its provisions and shall have all powers necessary for such purpose, including but not limited to the power:

(a) to interpret the Plan which power shall be exercised in the sole and exclusive discretion of the Committee Plan Administrator, including, without limitation, the sole and exclusive power and discretion to construe and interpret the Plan, including the intent of the Plan and any ambiguous, disputed or doubtful provisions of the Plan;
(b) to resolve all questions concerning the eligibility for benefits under the Plan and to require any person to furnish such information as it may reasonably request as a condition to receiving any benefit under the Plan;

(c) to determine the amount, manner or time of payment of benefits payable hereunder to Participants or their Beneficiaries;

(d) to assign or allocate any of its responsibilities among members of the Committee and to designate one or more persons (other than members of the Committee) to carry out its responsibilities (other than to manage or control the assets of the Plan);

(e) to authorize one or more of its number to exercise any of its powers or to execute or deliver any instrument or make any payment in its behalf; and

(f) to employ one or more persons to render advise with respect to any of its responsibilities under the Plan.

Notwithstanding anything which may be to the contrary to the foregoing, the Committee subject to Article 14, the Plan Administrator shall have the sole and exclusive power and discretion in carrying out of its duties under this Section 1413.5. All decisions of any type, including the interpretation and construction of the Plan, shall be final and binding on all parties and shall not be disturbed unless the Committee’s decisions are arbitrary and capricious.

1413.6 Claims Procedure

The Committee shall by rule or regulation establish a claims procedure under which each claimant shall receive notice in writing in the event any claim for benefits with respect to a Participant in the Plan has been denied; such notice shall set forth the specific reasons for such denial. Such claims procedure shall also provide an opportunity for full and fair review by the Committee of any denial of a claim, in accordance with Section 2560.503-1 of the applicable regulations of the Department of Labor. A claimant must file any request for review of a denied claim within 60 days after notice of denial has been received.

1413.7 Funding Policy

The Committee, subject to the provisions of Article 12, shall establish and carry out a funding policy and method consistent with the objectives of the Plan.

1413.8 Agents
The Committee or Plan Administrator may employ such agents and may enter into such reasonable contracts or arrangements for clerical and other service as it may deem desirable or necessary for the administration of the Plan.

1413.9. Compensation and Expenses

Members of the Committee or Plan Administrator may receive compensation for serving, and all expenses of the Committee or Plan Administrator and of the administration of the Plan and Fund shall be paid out of the Fund except to the extent paid by the Company. Notwithstanding the preceding sentence, persons who are full-time employees of the Company shall not receive additional compensation for serving as a member of the Committee or Plan Administrator. The Company may advance expenses to the Fund, subject to reimbursement, without obligating itself to pay such expenses.

1413.10. Breach by Another Fiduciary

The Company, the Board of Directors, the Committee (including the secretary), the Trustee or Trustees, and any person who is deemed to be a fiduciary under the Plan, shall not be liable for a breach of fiduciary responsibilities of another fiduciary under the Plan except to the extent (a) it shall have participated knowingly in, or knowingly undertaken to conceal, an act or omission of such fiduciary, knowing such act or omission was a breach of such fiduciary’s fiduciary responsibilities, (b) it shall have, through a breach of its fiduciary responsibilities, enabled such fiduciary to commit a breach of its fiduciary responsibilities, or (c) it shall have knowledge of a breach of fiduciary responsibilities by such fiduciary, and has not made reasonable efforts to remedy the breach.

14.11 Acts or Omissions of Designees

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The Company, the Board of Directors and the **Committee Plan Administrator** (including the secretary), shall not be liable for the acts or omissions of (a) any person or persons to whom any authority, power or responsibility has been allocated pursuant to Article 14 or (b) any person or persons who have been designated to carry out such authority, power or responsibility pursuant to Article 14, except to the extent (i) it shall have violated its fiduciary responsibilities with respect to (x) such allocation or designation, (y) the establishment or implementation of the allocation or designation procedures of Article 14 or (z) the continuation of any such allocation or designation, or (ii) it would otherwise be liable under Section 14.10.

### 14.12 Liability

In administering the Plan, neither the Company, the Board of Directors, the Committee (including the secretary), nor any director, officer or employee thereof, nor any person to whom any power or duty may be delegated by the Company, the Committee or the Board of Directors in connection with the administration of the Plan, shall be liable for any action or failure to act, except for it or his own willful and intentional malfeasance or misfeasance. The Company and its directors, officers and employees, the Board of Directors, the Committee (including the secretary), and each to whom any power or duty may be delegated by the Company, the Committee, or the Board of Directors in connection with the administration of the Plan, shall be entitled to rely conclusively upon, and shall be fully protected in, any action taken by them or any of them in good faith in reliance upon any table, valuation, certificate, opinion or report which shall be furnished to them or any of them by the Trustee, the Investment Manager, or by an actuary, accountant, counsel or other expert who shall be employed or engaged by the Company, the Committee or by the Board of Directors in connection with the administration of the Plan.

### 14.13 Discretionary Acts

Any discretionary acts to be taken under the Plan by the Company and its directors, officers and employees, the Board of Directors, the Committee or any person to whom any power or duty shall have been delegated by the Board of Directors, the Company or the Committee in connection with the administration of the Plan, with respect to classification or retirement of Participants, or benefits, shall be uniform in their nature and applicable to all those similarly situated. The interpretation and construction by the Company, the Board of Directors, the Committee or their delegates of any provisions of the Plan and their exercise of any discretion granted under the Plan shall be final and binding.

### 14.14 Indemnity

The Company, to the extent permitted by law, shall indemnify and hold harmless the members of the **Committee Plan Administrator committee**, the Board of Directors and any employee, officer or shareholder of the Company from and against all loss, damages, liability and
reasonable costs and expenses incurred in carrying out his responsibilities under the Plan, unless due to the bad faith or willful misconduct of such person, provided that such individual’s attorney’s fees and any amount paid in settlement shall be approved by the Company.
ARTICLE 14. DELEGATION OF FIDUCIARY RESPONSIBILITIES
BY PLAN ADMINISTRATOR OR BOARD

14.1. Appointment of Investment Manager

The Plan Administrator may appoint one or more Investment Managers to be designated by the Plan Administrator to serve at the pleasure of the Plan Administrator. In such case where an Investment Manager is appointed, the Plan Administrator will determine the portion of the assets of the Fund which are to be allocated to, or managed by, such Investment Manager.

14.2 Responsibilities of Investment Manager

An Investment Manager shall manage the investment and reinvestment of that portion of the assets of the Fund which have been allocated to such Investment Manager in accordance with the established investment policy. No Investment Manager shall provide, directly or indirectly, brokerage services to the Plan. An Investment Manager shall not have custody of any assets of the Fund in its capacity as Investment Manager (such responsibility being assigned to the Trustee), and shall have no responsibility with respect to the administration and operation of the Plan, the safekeeping of the assets of the Fund or the management of assets of the Fund which have not been allocated to such Investment Manager.

14.3. Appointment of Administrative Committee to Handle Other Fiduciary Functions

The Board of Directors may appoint an additional committee to perform fiduciary functions of the Plan Administrator other than the authority or discretion to manage or control assets of the Plan, which shall be retained by the Plan Administrator. Such additional committee shall be referred to herein as the “Administrative Committee.” To the extent that such Administrative Committee performs discretionary functions delegated to it, such committee shall be a fiduciary with respect to the Plan. The Administrative Committee shall consist of as many members as the Board may determine, which may be by position in the Company. The Administrative Committee shall have a chairman who shall be appointed from time to time by the Chairman of the Board from the members of the Administrative Committee. The Administrative Committee shall appoint a secretary who may be, but need not be, a member of the committee. The Administrative Committee shall discharge its duties for the exclusive benefit of Participants and their Beneficiaries.

The Administrative Committee may adopt such rules and regulations as it may deem desirable or necessary for the administration of the Plan on a consistent and nondiscriminatory
basis. All actions of the Administrative Committee shall be taken with the concurrence of a majority of its members, either at a meeting or in writing without a meeting. Written records shall be kept of meetings and actions of the Administrative Committee. No member of the Administrative Committee shall act on any matter under the Plan in which he alone is personally interested.

Members of the Administrative Committee may receive compensation for serving, and all expenses of the Administrative Committee and of the administration of the Plan and Fund shall be paid out of the Fund except to the extent paid by the Company. Notwithstanding the preceding sentence, persons who are full-time employees of the Company shall not receive additional compensation for serving as a member of the Administrative Committee. The Company may advance expenses to the Fund, subject to reimbursement, without obligating itself to pay such expenses.

The Company, to the extent permitted by law, shall indemnify and hold harmless the members of the Administrative Committee from and against all loss, damages, liability and reasonable costs and expenses incurred in carrying out the member’s responsibilities under the Plan, unless due to the bad faith or willful misconduct of such person, provided that such individual’s attorney’s fees and any amount paid in settlement shall be approved by the Company.

14.4. Breach by Another Fiduciary

The Plan Administrator, the Administrative Committee (including the secretaries of any committee), the Trustee or Trustees, and any other person who is deemed to be a fiduciary under the Plan, shall not be liable for a breach of fiduciary responsibilities of another fiduciary under the Plan except to the extent (a) it shall have participated knowingly in, or knowingly undertaken to conceal, an act or omission of such fiduciary, knowing such act or omission was a breach of such fiduciary’s fiduciary responsibilities, (b) it shall have, through a breach of its fiduciary responsibilities, enabled such fiduciary to commit a breach of its fiduciary responsibilities, or (c) it shall have knowledge of a breach of fiduciary responsibilities by such fiduciary, and has not made reasonable efforts to remedy the breach.
ARTICLE 15. AMENDMENT OR TERMINATION OF THE PLAN

15.1 Amendment

The Company reserves the right to modify, alter or amend this Plan or any Trust Agreement thereunder, by action of the Board of Directors; provided, however, that any amendment adopted by the Board of Directors which would cause the Plan or the Trust Agreement under the Plan to cease to meet the requirements of Section 401(a) of the Code, unless such result shall have been specifically intended as evidenced by an express statement of such intention in the resolution of such Board adopting such amendment, shall be null and void. No such amendment shall increase the duties or responsibilities of the Trustee without its consent thereto in writing. No such amendment shall have the effect of revesting in the Company the whole or any part of the principal or income or of diverting any part of such principal or income to purpose other than for the exclusive benefit of Participants and their Beneficiaries at any time prior to the satisfaction of all the liabilities under the Plan with respect to such persons. No such amendment shall be made which has the effect of reducing the accrued benefit of a Participant or of reducing the nonforfeitable percentage of a Participant’s accrued benefit below the nonforfeitable percentage thereof on the date such amendment is adopted or becomes effective, whichever is later.

15.2 Termination

This Plan is purely voluntary on the part of the Company, and the Company reserves the right, by action of the Board of Directors, to terminate the Plan and/or the Trust Agreement and to suspend or discontinue contributions at any time. Upon the termination or partial termination of the Plan, the rights of affected Participants to benefits accrued to the date of such termination or partial termination shall, to the extent funded as of such date, become non forfeitable, to the extent required by Section 411(d)(3) of the Code. The assets of the Plan, which are available to provide benefits, shall be allocated to provide Retirement Incomes, to the extent not already provided through insurance or annuity contracts which continue in force, to Participants and their Beneficiaries in accordance with the requirements of any applicable law. Prior to any such termination, the Plan shall be amended to provide specifically for such an allocation of the assets of the Plan. In accordance with Section 12.4, any Plan assets remaining in the Fund or with an insurance company after the satisfaction of all liabilities shall be returned to the Company.
ARTICLE 16. SECTION 401(a)(4) RESTRICTIONS

16.1 Restrictions Upon Plan Termination

In the event of Plan termination, the benefit of any highly compensated employee or highly compensated former employee, as those terms are defined under Section 414(q) of the Code, shall be limited to a benefit that is nondiscriminatory within the meaning of Section 401(a)(4) of the Code.

16.2 Restrictions on Distributions

(a) Except as provided in Section 16.2(b), annual payments to Participants described in Section 16.2(c) shall be restricted to an amount equal in each year to the payments that would be made on behalf of such Participant under:

(1) a straight life annuity that is the Actuarial Equivalent of the accrued benefit and other benefits to which the Participant is entitled under the Plan (other than a Social Security supplement), and

(2) the amount of the payments that the Participant is entitled to receive under a Social Security supplement.

(b) The restrictions in Section 16.2(a) shall not apply if any one of the following requirements is satisfied:

(1) after payment to a Participant described in Section 16.2(c) of all benefits payable to such Participant under the Plan, the value of Plan assets equals or exceeds 110 percent of the value of current liabilities, as defined in Section 412(l)(7) of the Code;

(2) the value of the benefits payable to a Participant described in Section 16.2(c) under the Plan is less than 1 percent of the value of current liabilities before distribution; or

(3) the value of the benefits payable to a Participant described in Section 16.2(c) under the Plan does not exceed the amount described in Section 411(a)(11)(A) of the Code (relating to restrictions on certain mandatory distributions).

(c) The restrictions in the Section 16.2 shall apply solely to the 25 highly compensated Employees and former Employees with the greatest compensation in the current or any prior year.
16.3 Application of Restrictions

In the event that it should be subsequently determined by statute, court decision to which the Commissioner of Internal Revenue has acquiesced, or regulations or rulings of the Internal Revenue Service that the provisions of this Article 16 are no longer necessary to qualify the Plan under the Code, this Article shall thereupon be ineffective without the necessity of further amendment of the Plan.
ARTICLE 17. GENERAL PROVISIONS

17.1 Source of Payment

Retirement Income payments and other benefits under this Plan shall be payable only out of the Fund or through the use of insurance or annuity contracts. No persons shall have any rights under the Plan with respect to the Fund, or against the Trustee or Company, except specifically provided for herein.

17.2 Small Benefits

(a) If a Participant’s service with the Company and any Affiliate is terminated for any reason, and the present value of the Retirement Income under Article 6 or 10 or the pre-retirement spouse’s death benefit under Article 9 payable to any Participant or his Beneficiary shall be less than equal to $5,000, then the Committee shall instruct the Plan Administrator to instruct the Trustee and/or the insurance company or companies to pay the present value thereof in a lump sum upon the Participant’s termination of service. If the present value of the nonforfeitable Retirement Income or pre-retirement spouse’s death benefit payable to the Participant or his spouse is $0, then such benefit shall be deemed to have been fully distributed upon the Participant’s termination of service. The present value of the Retirement Income or pre-retirement spouse’s death benefit shall be the Actuarial Equivalent lump sum distribution, as defined in Section 2.1.

(b) A distributee may elect, at the time and in the manner prescribed by the Plan Administrator, to have any portion of an eligible rollover distribution paid directly to an eligible retirement plan specified by the distributee in a direct rollover. An eligible rollover distribution is any distribution of all or any portion of the balance to the credit of the distributee, except that an eligible rollover distribution does not include any distribution that is one of a series of substantially equal periodic payments (not less frequently than annually) made for the life (or life expectancy) of

Further, for distributions on or after March 28, 2005, if the Participant’s vested Accrued Benefit is greater than $1,000 and not more than $5,000, distribution may not be made without the consent of the Participant.
the distributee or the joint lives (or joint life expectancies) of the distributee and the distributee’s
designated beneficiary, or for a specified period of ten years or more; any distribution to the extent
such distribution is required under Section 401(a)(9) of the Code; and any hardship distributions. An
eligible retirement plan is an individual retirement account described in Section 408(a) of the Code,
an individual retirement annuity described in Section 408(b) of the Code, an annuity plan described
in Section 403(a) of the Code, or a qualified trust described in Section 401(a) of the Code, that
accepts the distributee’s eligible rollover distribution. However, in the case of an eligible rollover
distribution to the surviving spouse, an eligible retirement plan is an individual retirement account or
individual retirement annuity. A distributee includes an employee or former employee. In addition,
the employee’s or former employee’s surviving spouse and the employee’s or former employee’s
spouse or former spouse who is the alternate payee under a qualified domestic relations order, as
defined in Section 414(p) of the Code, are distributees with regard to the interest of the spouse or
former spouse. A direct rollover is a payment by the plan to the eligible retirement plan specified by
the distributee.

For purposes of the direct rollover provisions above, an eligible retirement plan shall also
mean an annuity contract described in Section 403(b) of the Code and an eligible plan under Section
457(b) of the Code which is maintained by a state, political subdivision of a state, or any agency or
instrumentality of a state or political subdivision of a state and which agrees to separately account for
amounts transferred into such plan from this plan. The definition of eligible retirement plan shall
also apply in the case of a distribution to a surviving spouse, or to a spouse or former spouse who is
the alternate payee under a qualified domestic relation order, as defined in Section 414(p) of the
Code.

For purposes of the direct rollover provisions above, a portion of a distribution shall not fail
to be an eligible rollover distribution merely because the portion consists of after-tax employee
contributions which are not includible in gross income. However, such portion may be transferred
only to an individual, eligible retirement account or annuity described in Section 408(a) or (b) of the
Code, or to a qualified defined contribution plan described in Section 401(a) or 403(a) of the Code
that agrees to separately account for amounts so transferred, including separately accounting for the
portion of such distribution which is includible in gross income and the portion of such distribution
which is not so includible. The Plan will permit a direct rollover of an eligible rollover distribution to
a Roth IRA.

(c) Where a small benefit under this section is payable to a Beneficiary other than the
Participant’s spouse, the Plan will permit a non-spouse Beneficiary to request a direct trustee-to-
trustee transfer to an individual retirement account or annuity described in Code section 402(c)((11).
When made these transfers shall be treated as an eligible rollover distribution.

(d) Notwithstanding anything herein to the contrary, if a Participant who receives a
distribution under this Section 17.2 is subsequently reemployed by the Company, the Participant’s
Benefit base upon subsequent retirement shall be computed in accordance with Section 6.1, reduced
by the amount of the Benefit Base which was used to determine the benefit previously received under this Section 17.2.

17.3 Inalienability of Benefits

Except as otherwise provided by law or by the issuance of a qualified domestic relations order (within the meaning of Section 206(d) of ERISA), no person shall have the right to assign, alienate, transfer, hypothecate or otherwise subject to lien his interest in or his benefit under the Plan; nor shall benefits under the Plan be subject to the claims of any creditor.

17.4 Merger or Consolidation

In the event of any merger or consolidation of the Plan with, or transfer of any assets or liabilities of the Plan to, any other plan, each Participant shall be entitled to receive a benefit immediately after such merger, consolidation, or transfer (computed as if such other plan had then terminated) which is equal to or greater than the Retirement Income he would have been entitled to receive immediately before such merger, consolidation, or transfer (computed as if the Plan had then terminated); provided further that, in the event of a plan spin-off within the meaning of Section 414(l)(2) of the Code, the excess assets of the Plan shall be allocated in accordance with the requirements of that Section and regulations issued by the Secretary of the Treasury.

17.5 Payment Due an Incompetent

If it shall be found that any person to whom a payment is due hereunder is unable to care for his affairs because of physical or mental disability, the CommitteePlan Administrator shall have the authority to cause the payments becoming due to such person to be made to the guardian, committee, or other legal representative, wherever appointed, of such person, and, if none, to the first surviving class of the following successive preference payees: (a) such person’s spouse, (b) such person’s parent, (c) the individual with whom such person resides, (d) any individual having the care and control of such person, or (e) such person personally. Neither the Company, the CommitteePlan Administrator, nor the Trustee shall be responsible to see to the application of such payments. Payments made pursuant to such power shall operate as a complete discharge of the Company, the CommitteePlan Administrator, the Trustee and the Fund to the extent of such payments.

17.6 No Right to Employment

The Plan confers no right upon an Employee to continue his employment either with the Company or any Affiliate.
17.7  **Controlling Law**

The administration of the Plan shall be governed by the laws of the State of Arkansas, except to the extent preempted by the laws of the United States, and any persons or corporations who now are or shall subsequently become parties to the Plan shall be deemed to consent to this provision.

17.8  **Approval of Internal Revenue Service**

The provisions of the Plan are subject to obtaining approval by the Internal Revenue Service and to any amendments necessary to obtaining or retaining such approval.

17.9  **Right to Recover Excess Payments**

In the event a payment is made erroneously to an individual or exceeds the amount properly payable under the terms of the Plan, the Plan shall have the right to reduce future payments payable to or on behalf of such individual by the amount of the erroneous or excess payments. This right to offset shall not limit the right of the Plan to recover the total amount of an erroneous or excess payment in any other manner from the person to or for whom the payment was made.
ARTICLE 18. TOP-HEAVY PROVISIONS

The provisions of this Article 18 shall become applicable only under the circumstances described hereunder:

18.1 Top-Heavy Defined

For purposes of this Article 18, the Plan shall be “Top-heavy” with respect to any Plan Year if, as of the last day of the preceding Plan Year, the present value, as determined as of the same valuation date and utilizing the same interest rates used for computing plan costs for minimum funding, of the cumulative accrued benefits for “key employees,” as defined in Section 416(i) of the Code, under the Plan and all other plans in the “aggregation group” exceeds 60 percent of the present value of the cumulative accrued benefits under all such plans for all employees. For purposes of this Section, “aggregation group” shall mean (i) each plan of the Company or an Affiliate in which a “key employee” is a Participant, and (ii) each other plan of the Company or an Affiliate which enables any plan described in (i), above, to meet the antidiscrimination or participation requirements of the Code. For purposes of this Section, if the Participant is a non-key employee with respect to the Plan for any Plan Year, but such Participant was a key employee with respect to such Plan for any prior Plan Year, any accrued benefit for such Participant shall not be taken into account. If a Participant has not performed any service for the Company or an Affiliate at any time during the 1-year period ending on the determination date for any Plan Year, any accrued benefit for such Participant (and the account of such Participant) shall not be taken into account.

18.2 Minimum Benefits

The following provisions shall be applicable to Participants for any Plan Year with respect to which the Plan is Top-heavy:

(a) In lieu of the service requirement for eligibility for a deferred vested retirement allowance specified in Section 10.1, any Participant who has completed 3 years of Vesting Service shall be entitled, upon termination of service with the Company and any Affiliate to a deferred vested retirement allowance equal to his accrued Retirement Income determined in accordance with the provisions of Section 10.1 and Section 18.2(b) below.

(b) The accrued Retirement Income of a Participant who is a non-key employee who has completed at least the equivalent of 1,000 hours of service during the Plan Year, regardless of whether such Participant is employed on the last day of the Plan Year, shall not be less than 2 percent of his average Earnings multiplied by the number of years of his Vesting Service, not in excess of 10, during the Plan Years for which the Plan is Top-heavy. For purposes of this Section 18.2, Earnings shall be defined in Section 11.1 and average Earnings
shall mean the average annual Earnings of a Participant for the five consecutive years of his Vesting Service after December 31, 1983, during which he received the greatest aggregate Earnings from the Company or an Affiliate excluding any Earnings for service after the last Plan Year with respect to which the Plan is Top-heavy.

18.3 Ceases Top-heavy Status

If the Plan is Top-heavy with respect to a Plan Year and ceases to be Top-heavy for a subsequent Plan Year, the following provisions shall be applicable:

   (a) The accrued Retirement Income in any subsequent Plan Year shall not be less than the minimum accrued Retirement Income provided in Section 18.2(b) above, computed as of the end of the most recent Plan Year for which the Plan was Top-heavy.

   (b) The nonforfeitable percentage of a Participant’s accrued Retirement Income on and after the date on which the Plan ceases to be Top-heavy (the “Cessation Date”) shall be determined in accordance with Section 10.1; provided, however, that the application of this provision shall not result in a reduction in the nonforfeitable percentage of such Participant’s accrued Retirement Income determined prior to the Cessation Date in accordance with the schedule set forth in Section 18.2 provided further that each Participant with at least 3 years of Vesting Service may elect, within 60 days after the later of the Cessation Date or the issuance of written notice by the Company, to have his nonforfeitable percentage computed under the Plan without regard to the cessation of Top-heavy status.

IN WITNESS WHEREOF, Southwest Power Pool, Inc. has caused this Plan, effective as of January 1, 2008, except as otherwise provided, to be duly executed this _______ day of _______________, 2008.

SOUTHWEST POWER POOL, INC.

By______________________________
Title_____________________________

59
APPENDIX A

to the

Southwest Power Pool, Inc. Retirement Plan

Table of Adjustment Factors for Determining Actuarial Equivalence

Procedural Rules
Applicable to all the factors:

--All ages refer to the age at last birthday as of the date benefit payments are to begin.

--Age differences for Joint and Survivor Annuity are calculated exactly. If the Joint Annuitant has the same birth month and day, and the number of years applies to two rows, the factor that results in the larger benefit will be utilized.
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<th>58</th>
<th>61</th>
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### If Beneficiary’s Age is Less Than:

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### Joint and 100% Survivor Pension

<table>
<thead>
<tr>
<th>Participant’s Age Less than Beneficiary’s Age is</th>
<th>If Participant’s Age is Less Than:</th>
<th>But Greater Than or Equal To:</th>
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<tr>
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### E. 10-Year Certain and Life Thereafter

If Participant’s Age is:

<table>
<thead>
<tr>
<th>Less Than</th>
<th>but</th>
<th>Greater Than or Equal to</th>
<th>Factor</th>
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</tbody>
</table>
F. Social Security Leveling Option

1. Multiply Estimated Age 62 Primary Social Security Benefit by Appropriate Factor Given Below:

<table>
<thead>
<tr>
<th>Age of Participants</th>
<th>Factor</th>
</tr>
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<tbody>
<tr>
<td>55</td>
<td>.48</td>
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<tr>
<td>56</td>
<td>.43</td>
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<tr>
<td>57</td>
<td>.37</td>
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<td>58</td>
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<td>.25</td>
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<tr>
<td>60</td>
<td>.18</td>
</tr>
<tr>
<td>61</td>
<td>.10</td>
</tr>
</tbody>
</table>

2. Subtract result of (1) from Benefit Base after reduction for early retirement. If negative, option cannot be selected.

3. Pre-age 62 total single life pension is equal to the sum of the estimated age 62 Primary Social Security benefit, plus benefit in (2).

4. Benefit on and after 62 is benefit in (2).
Southwest Power Pool, Inc.

HUMAN RESOURCES COMMITTEE

Recommendation to the SPP Board of Directors

Request to name SPP Human Resources Committee as named fiduciary for 401(k) Plan

And

Creation of Administrative Committee for all SPP Retirement Plans

October 8, 2013

Organizational Roster

The following members represent the Human Resources Committee:

- Ms. Phyllis Bernard, Chair  SPP Director
- Mr. Julian Brix  SPP Director
- Ms. Lori Dunn  Calpine Corporation
- Mr. Duane Highley  Arkansas Electric Cooperative Corporation
- Mr. Mike Palmer  Empire District Electric Company
- Mr. Noman Williams  Sunflower Electric Power Corporation

Background

The SPP Human Resources Committee has evaluated the roles and responsibilities of fiduciary, trustee and plan administrator for the SPP 401(k) and Defined Benefit Retirement Plans. The committee had identified a need to clarify their role as fiduciary for the 401(k) plan and to identify a plan administrator role for both retirement plans.

Analysis

The SPP Defined Benefit Retirement Plan, “Southwest Power Pool, Inc. Retirement Plan” (“Plan”), has been updated to include a provision that states: “The Board of Directors may appoint an additional committee to perform fiduciary functions of the Plan Administrator other than the authority or discretion to manage or control assets of the Plan, which shall be retained by the Plan Administrator. Such additional committee shall be referred to herein as the “Administrative Committee.” To the extent that such Administrative Committee performs discretionary functions delegated to it, such committee shall be a fiduciary with respect to the Plan. The Administrative Committee shall consist of as many members as the Board may determine which may be by position in the Company.”

The SPP Human Resources Committee recommends the SPP Board of Directors exercise this option to name an Administrative Committee by SPP job title to consist of the following: SPP CEO, General Counsel, CFO, and Director, Corporate Services.

Recommendation

The Human Resources Committee recommends Southwest Power Pool Board of Directors amend the 401(k) plan document to specifically name the SPP Human Resources Committee as fiduciary and create an Administrative Committee for both SPP retirement plans. This Administrative Committee will consist of the SPP CEO, General Counsel, CFO and Director, Corporate Services. The Administrative Committee will report to the Human Resources Committee.

Approved:  Human Resources Committee  October 8, 2013

Action Requested:  Approve Recommendation
Southwest Power Pool, Inc.
CORPORATE GOVERNANCE COMMITTEE
Recommendation to the Board of Directors
October 29, 2013

Vacancy

Background
There will be a vacancy on the Strategic Planning Committee effective December 1, 2013. In accordance with SPP’s Bylaws, the Corporate Governance Committee recommends a candidate to the Board of Directors for consideration and appointment.

Analysis
Mel Perkins is retiring from Oklahoma Gas and Electric, and thus from his position on the Strategic Planning Committee effective December 1, 2013. The members of the Transmission Owner member sector were notified of the pending vacancy. Following consideration of several candidates, the Committee selected Venita McCellon-Allen (AEP) to nominate to fill this vacancy.

The Corporate Governance Committee considered the candidates, his/her backgrounds, and the balance of member representation on the various SPP committees.

Recommendation
The Corporate Governance Committee recommends the appointment of Venita McCellon-Allen (AEP) to serve on the Strategic Planning Committee, effective December 1, 2013.

Approved: Corporate Governance Committee: August 29, 2013

Action Requested: Approve recommendation
Southwest Power Pool, Inc.
CORPORATE GOVERNANCE COMMITTEE
Recommendation to the Board of Directors
October 29, 2013

Board Committee Scopes

Background
At the Corporate Governance Committee’s recommendation, the Board of Directors approved revising the SPP Bylaws to remove the detailed activities for each, capturing those in each committee’s respective Scope document. That filing has been made and is pending at FERC.

Analysis
Assuming the filing is approved, SPP’s Bylaws will be revised as of the effective date. In anticipation, The Corporate Governance Committee has reviewed the existing responsibilities in the Bylaws, as well as various Scope documents. Updated Scope documents are provided for consideration, reflecting the duties assigned, current practice, and consistency in formatting.

Recommendation
The Corporate Governance Committee recommends approval of the Scopes for the Board committees as presented.

Approved: Corporate Governance Committee TBD, 2013
unanimous

Action Requested: Approve recommendation
Purpose
The Corporate Governance Committee is responsible for the overall governance structure, including nominations, for the company in accordance with its scope as approved by the Board of Directors.

Scope of Activities
a) Seek input from the Board of Directors, the Members Committee, or the Trustees as to the skills needed to fill any vacancy under consideration;

b) In the event of a vacancy or the replacement of an existing director, provide candidates identified by an independent executive search firm for consideration to the Members for election to the Board of Directors;

c) In the event of a vacancy or the replacement of an existing Trustee, provide candidates for consideration to the Members for election to the Regional Entity Trustees;

d) In the event of a vacancy or the replacement of an existing Members Committee representative, provide candidates for consideration to the Membership for election to the Members Committee;

e) Fill vacancies for Organizational Groups in accordance with the Bylaws,

f) Monitor the composition of the Board of Directors to ensure balance, independence, maintenance of qualifications under any applicable laws, avoidance of conflict of interest, and periodic review of the criteria for independence set out in the Bylaws and appropriate regulatory bodies, recommending changes, as appropriate;

g) Recommend to the Board of Directors the appointment of Organizational Group representatives and leadership except for the Corporate Governance Committee, whose representatives are elected by members in each category; the Members Committee, whose representatives are elected by the Membership, and the
Market and Operations Policy Committee, whose representatives are appointed by the Members;

h) Develop criteria governing the overall composition of the Board of Directors for recommendation to the Membership;

i) Develop criteria governing the overall composition of the Regional Entity Trustees for recommendation to the Membership;

j) Coordinate an annual review and assessment of the effectiveness of the Board of Directors, its structure, and process;

k) Coordinate an annual review and assessment of the effectiveness of the Regional Entity Trustees, its structure, and process;

l) Review annually the structure of the Organizational Groups, and together with the Organizational Group Chairs, the charters of each Organizational Group, and recommend changes to the Board of Directors, as appropriate;

m) Review the self-assessments of the Organizational Groups to assure that they are being done on a consistent basis;

n) Develop recommendations for the Board of Directors regarding a Chair/Vice Chair succession policy;

o) Recommend compensation levels for the Board of Directors and Regional Entity Trustees to the Membership;

p) Oversee and receive reports on business continuity plans and assessments;

q) Complete a self-assessment annually to determine how effectively the CGC is meeting its responsibilities; and

r) Perform such other functions as the Board of Directors may delegate or direct.

**Representation**

To the extent that the membership allows, the CGC shall be comprised of nine members. One representative shall be the President of SPP who will serve as the Chair; one representative shall be the Chairman of the Board, unless his/her position is under consideration, in which case the Vice Chairman of the Board; one representative
shall be representative of and selected by investor owned utilities Members; one representative shall be representative of and selected by co-operatives Members; one representative shall be representative of and selected by municipals Members; one representative shall be representative of and selected by independent power producers/marketers Members; one representative shall be representative of and selected by state/federal power agencies Members; one representative shall be representative of and selected by alternative power/public interest Members; and one representative shall be representative of and selected by large/small retail Members.

**Reporting**
The Corporate Governance Committee reports directly to the Board of Directors.
Southwest Power Pool, Inc.
FINANCE COMMITTEE
Organizational Group Scope Statement
_______________________, 2013

Purpose
The Finance Committee (FC) is responsible for all aspects of financial functions for the company in accordance with its scope as approved by the Board of Directors.

Scope of Activities
a) Develop policies for management of the company’s capitalization, financing and long-term contracts;

b) Review and approve annually significant financial and compliance policies that fall under the purview of the Committee;

c) Monitor the methodology of cost recovery to ensure continuing equity for Members;

d) Oversee development of the annual operating budget and recommend a budget and rate for Board approval;

e) The Committee shall annually recommend for Board of Directors approval engagement of independent auditors;

f) Review and discuss with management and the independent auditors, prior to the public dissemination, the corporation’s annual audited financial statements with primary focus on the quality and integrity of the statements;

g) Review with management and the independent auditors their assessments of the adequacy of internal financial controls and the resolution of any identified material weaknesses or reportable conditions;

h) Review and approve the company’s Credit Policy, and resolve disputes related to it.

i) Oversee and approve corporate/signature authority levels.
j) Report to the Board of Directors on the financial status of the defined benefit and retiree healthcare plans and recommend any funding requirements/strategies for the plans;

k) Review annually, the Investment Policy Statements for the Company’s retirement plan, post-retirement healthcare plan, and other similar plans, to ensure the Investment Policy Statements continue to be appropriate for the goals of the plans;

l) Engage and monitor the performance of Investment Managers who have discretionary investment powers for the Company’s defined benefit retirement and post-retirement healthcare plans;

m) Review reports of the actuaries and provide input to the assumptions used to develop the actuarial reports;

n) Review as necessary, with the Company’s counsel, any legal matter that could have a significant impact on the Company’s financial statements;

o) Retain consultants and other experts, as necessary, to advise and guide the Committee in fulfilling its duties, including the authority to approve the fees payable to such advisors and any other terms of retention;

p) Review and discuss the Company’s major financial risk exposures and the steps management has taken to monitor and control such exposures.

q) Report its activities at the next meeting of the SPP Board of Directors following a meeting of the Committee.

r) Perform an annual assessment of the effectiveness of the Finance Committee and report to the Board of Directors the results and any recommendations for change.

s) Performs such other functions as the Board of Directors may delegate or direct.

The Committee is not responsible for certifying the corporation’s financial statements or guaranteeing the auditor’s report. The fundamental responsibility for the corporation’s financial statements and disclosures rests with management.

Representation
The FC shall be comprised of six members. Two representatives shall be from the Board of Directors, one of whom shall serve as the Chair; two representatives from the
Transmission Owning Member sector as nominated by the Corporate Governance Committee; and two representatives from the Transmission Using Member sector as nominated by the Corporate Governance Committee.

**Reporting**
The Finance Committee reports directly to the Board of Directors.
Southwest Power Pool, Inc.

HUMAN RESOURCES COMMITTEE

Organizational Group Scope Statement

__________________, 2013

Purpose

The Human Resources Committee (HRC) is responsible for the development of personnel policies, including benefits structures, for the company in accordance with its scope as approved by the Board of Directors.

Scope of Activities

a) Review and monitor organizational structure, succession, and personnel plans, ensuring continuous alignment with the SPP Strategic Plan.

b) Approve overall compensation policies and funding and review administration of those policies.

c) Review and approve employee and executive benefit and health care plans. Ensuring plans are competitive in the marketplace, responsive to the law, and provide satisfaction to beneficiaries within a cost constrained budget that effectively meets stakeholder needs. Appoint trustees to administer employee benefit plan trusts and define the rights, powers and responsibilities of trustees. Provide oversight of the design and investment strategy of the defined contribution employee benefit plan.

d) Review annually the slate and structure of SPP’s retirement plans ensuring compliance with applicable laws, ensure benefits are consistent with SPP’s strategic values.

e) Review annually the Investment Policy Statements for the Company’s defined contribution employee benefit plan, and supplemental defined contribution plans to ensure the Investment Policy Statements continue to be appropriate for the goals of the plans.

f) Engage Investment Managers for the Company’s defined contribution employee benefit plan, and supplemental defined contribution plans.
g) Oversee SPP programs designated to maintain ethical standards and facilitate open door procedures to report violations. Ensure documentation of standards and procedures, proper functioning of programs and provisions of ongoing training to all SPP employees.

h) Review and approve SPP’s employee and executive performance evaluation processes.

i) Ensure the critical job functions and goals of the SPP President are documented and communicated to the SPP President and, annually, ensure the SPP President receives a documented review of the performance against the stated critical job functions and goals. Recommend compensation and benefit adjustments for the SPP President.

j) Retain consultants and other experts, as necessary, to advise and guide the Committee in fulfilling its duties and achieving the desired workplace environment.

k) Report its activities at the next meeting of the SPP Board of Directors following a meeting of the Committee.

l) Perform an annual assessment of the effectiveness of the Human Resources Committee and report to the Board of Directors the results and make any recommendations for change.

m) Perform such other duties as the Board of Directors may delegate or direct.

**Representation**
The HRC shall be comprised of six members. Two representatives shall be from the Board of Directors, one of whom shall serve as the Chair; two representatives from the Transmission Owning Member sector as nominated by the Corporate Governance Committee; and two representatives from the Transmission Using Member sector as nominated by the Corporate Governance Committee.

**Reporting**
The Human Resources Committee reports directly to the Board of Directors.
Purpose
The Markets and Operations Policy Committee is responsible, through its designated Organizational Groups, for developing and recommending policies and procedures related to the technical operations for the company in accordance with its scope as approved by the Board of Directors.

Scope of Activities
a) Recommend practices for system design, planning, adequacy, regional transmission service tariff, interconnections, operation, reliability, market designs and efficiency, and market power mitigation that will help to assure efficient and reliable power supply among the systems in SPP and SPP transmission customers;

b) Coordinate and review with ERO Policies and Standards and their applicability to SPP, its Members, and Registered Entities in the SPP footprint;

c) Present any Regional Reliability Standards for ERO adoption in accordance with SPP’s Standards Development Process.

d) Coordinate and oversee the work of any Standards Development Team(s).

e) Report to the Trustees on the status of all standards recommended by working groups reporting to the MOPC in accordance with the SPP Standards Development Process.

f) Make appropriate recommendations to the Board of Directors and Regional Entity Trustees regarding SPP’s compliance with ERO Policies and Standards;

g) Review Member operating plans and problems that are pertinent to SPP planning and operation;

h) Maintain an annual series of load flow and short circuit models, econometric dispatch models, and associated stability data bases representing the current
and planned electric network of the region, and maintain a data base of all transmission, generation, and supporting facilities within SPP;

i) Review and assess the current and planned electric system of the region;

j) Make use of studies available from other regions;

k) Recommend to the Board of Directors criteria for planning, operations, and to assist in the efficiency and vitality of the wholesale electricity market;

l) Coordinate inter-regional and intra-regional plans to facilitate planning, information exchange, and operations between inter-regional and intra-regional groups;

m) Develop a coordinated plan for intra-regional transmission for greater efficiency and reliability of electric power supply;

n) Recommend to the Board of Directors and Members individual or joint action to improve the operation of the systems comprising SPP;

o) Respond to activities as requested by the Strategic Planning Committee and the Board of Directors;

p) Monitor the current state and evolution of the electric energy supply industry and proactively recommend commercial practices that meet industry needs and promote commerce;

q) Work with all SPP Organizational Groups to promote high standard of operational reliability;

r) Continue coordination of its efforts with the efforts of North American Energy Standards Board (NAESB) and the ISO/RTO Council (IRC) including periodic review of NAESB business practices and IRC policies and their applicability to SPP and its Members;

s) Complete a self-assessment annually to determine how effectively the MOPC is meeting its responsibilities; and

t) Perform such other functions as the Board of Directors may delegate or direct.
**Representation**
Each SPP Member shall appoint a representative to the Market and Operations Policy Committee (MOPC). Each representative designated shall be an officer or employee of the Member. The Board of Directors will appoint the Chair and Vice Chair of the MOPC. Each member of the MOPC may continue to be a member thereof until the appropriate Member appoints a successor.

**Reporting**
The Markets and Operations Policy Committee reports directly to the Board of Directors.
Purpose
The Oversight Committee (OC) is responsible for monitoring compliance with SPP and regulatory policies for the company in accordance with its scope as approved by the Board of Directors.

Scope of Activities
a) Oversee the process of monitoring compliance to SPP and NERC policies other than that assigned to the Regional Entity Trustees under these Bylaws;

b) Oversee the Internal Audit function and receive regular reports, except for work associated with controls audits and other financial requirements;

c) Oversee the Market Monitoring function and receive regular reports;

d) Oversee the Compliance function and receive regular reports;

e) Independently review activities of the Staff;

f) Oversee the process for and approve Independent Expert Panels associated with the Order 1000 implementation process;

g) Discuss with management and the independent auditors the company’s guidelines and policies with respect to corporate risk assessment and risk management;

h) Hear and rule on appeals from Members regarding penalty assessment or fine distribution, other than those resulting from the Compliance Monitoring and Enforcement Program, prior to dispute resolution proceedings;

i) Recommend Criteria changes necessary for enforcement of mandatory compliance and in response to unclear enforcement provisions of Criteria;
j) Grant specific additional authority to the Staff responsible for the compliance monitoring function when needed to perform challenging investigations;

k) Complete a self-assessment annually to determine how effectively the OC is meeting its responsibilities; and

l) Perform such other functions as the Board of Directors may delegate or direct.

**Representation**
The OC shall be comprised of three members from the Board of Directors.

**Reporting**
The Oversight Committee reports directly to the Board of Directors.
Purpose
The Strategic Planning Committee (SPC) is responsible for the development and recommendation of strategic direction for the company in accordance with its scope as approved by the Board of Directors.

Scope of Activities
a) Gather information from the SPP Members, customers, Staff, regulatory jurisdictions, market monitors, and legislative bodies on industry trends, forecasts and directions;

b) Assess the industry environment in which SPP will be operating;

c) Assess SPP’s capabilities and competencies against the industry environment, including coordination with neighboring entities;

d) Develop and recommend to the Board of Directors a mission and vision statement and accompanying goals and objectives;

e) Formulate strategies to ensure achievement of SPP’s mission statement, goals, objectives, and responsibilities, and recommend necessary modifications to SPP processes to carry out these strategies;

f) Initiate definition of futures for transmission planning models;

g) Work with other Organizational Groups in developing related action plans, schedules and budgets;

h) Complete a self-assessment annually to determine how effectively the SPC is meeting its responsibilities; and

i) Perform such other functions as the Board of Directors may delegate or direct.
**Representation**
The SPC shall be comprised of eleven members. Three representatives shall be from the Board of Directors; four representatives from the Transmission Owning Member sector as nominated by the Corporate Governance Committee; and four representatives from the Transmission Using Member sector as nominated by the Corporate Governance Committee.

**Reporting**
The Strategic Planning Committee reports directly to the Board of Directors.
Southwest Power Pool, Inc.
CORPORATE GOVERNANCE COMMITTEE
Recommendation to the Board of Directors
October 29, 2013
Recovery of FERC Penalty

Organizational Roster
The following persons are members of the Corporate Governance Committee:

Nick Brown (Chairman)  Jim Eckelberger, Director
Ricky Bittle, AECC       Robert Janssen, Dogwood
Jason Fortik, LES       Mel Perkins, OG&E
John McClure, NPPD      Stacy Duckett (Staff Secretary)

Background
On July 10, 2013, FERC issued an Order Approving Stipulation and Consent Agreement approving an agreement between SPP and FERC to settle an investigation conducted by FERC into possible violations of Reliability Standards associated with SPP’s reliability coordination of a portion of the Bulk Power System. FERC initiated an investigation into whether SPP had complied with Reliability Standards applicable to an event that occurred on December 26, 2007. This investigation focused on SPP’s functioning as a NERC-registered reliability coordinator both as the ICT and for the SPP RTO. SPP agreed to pay a total civil penalty of $50,000, and to conduct other mitigation described in the Stipulation and Consent Agreement. While FERC and NERC staff concluded that SPP violated two requirements of two Reliability Standards, SPP neither admits nor denies FERC and NERC’s determinations.

Attachment AP of the SPP Open Access Transmission Tariff (“Tariff”) requires SPP to submit a filing to recover the cost of such payment and to propose to FERC how such cost should be allocated within SPP.

Analysis
At the time of the alleged violations, SPP was acting under the Tariff in the provision of tariff services. Tariff Schedule 1-A permits SPP to collect from Tariff Customers up to 100% of its expenses and other costs not otherwise collected. Utilizing Schedule 1-A for the recovery of the settlement amount would ensure that the cost associated with the FERC penalty is borne by Customers receiving tariff services rather than requiring that such cost be borne solely by SPP’s membership.

Recommendation
The Corporate Governance Committee recommends to recover and allocate the costs of the FERC penalty under Schedule 1-A.

Approved: Corporate Governance Committee August 29, 2013
Unanimous

Action Requested: Approve Recommendation
Southwest Power Pool, Inc.
CORPORATE GOVERNANCE COMMITTEE
Recommendation to the Board of Directors
October 29, 2013

Change in Formula for Financial Obligations upon Withdrawal

Background
The formula for calculation of an entity’s share of SPP, Inc.’s financial obligations when withdrawing from the organization includes a factor for “NEL in SPP”. NEL is Net Energy for Load, and is defined as “The electrical energy requirements of an electric system are defined as system net generation plus energy received from others, less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage at energy storage facilities.”

Analysis
This component of the formula requires additional clarification/updating. When originally crafted, there was only one SPP footprint (the reliability region), and it was the function generating the majority of costs incurred by SPP. In recent years, the organization has evolved to have several footprints, and the markets footprint has generated the majority of costs incurred by SPP. In addition, the NEL numbers used have been provided by the reporting member with no independent verification available. The NEL numbers are used for no other purpose than calculating withdrawal obligations.

The Corporate Governance Committee discussed options, and determined that a more appropriate calculation is for “The load served by transmission facilities under the SPP Open Access Transmission Tariff.” In determining how to implement this, Staff has determined that Schedule 12 Load is the appropriate factor to use since it is currently reported to SPP for other purposes and somewhat verifiable.

Recommendation
The Corporate Governance Committee recommends approval of the change in the formula for financial obligations upon withdrawal. Filing of this change is pending concurrence from SPP’s lenders, which is currently being sought.

Approved: Corporate Governance Committee September 20, 2013 Via email unanimous

Action Requested: Approve recommendation
1.0 Definitions

Affiliate Relationships
Affiliate Relationships are relationships between SPP Members that have one or more of the following attributes in common:

(a) are subsidiaries of the same company;
(b) one Member is a subsidiary of another Member;
(c) have, through an agency agreement, turned over control of a majority of their generation facilities to another Member;
(d) have, through an agency agreement, turned over control of a majority of their transmission system to another Member, except to the extent that the facilities are turned over to an independent transmission company recognized by FERC;
(e) have an exclusive marketing alliance between Members; or
(f) ownership by one Member of ten percent or greater of another Member.

Articles of Incorporation
SPP’s articles of incorporation as filed with the state of Arkansas.

Board of Directors
The Board of Directors of SPP, which shall manage the general business of SPP pursuant to these Bylaws.

Bylaws
These bylaws.

Criteria
Planning and operating standards and procedures as approved by the Board of Directors.

Existing Obligations
Certain financial obligations as defined in Section 8.7.1 of these Bylaws.

ERO
The Electric Reliability Organization under FERC jurisdiction that regulates reliability of the electric power grid.

Member
An entity that has met the requirements of Section 2.2 of these Bylaws.

Membership
The collective Members of SPP.

Membership Agreement
The contract, that specifies the rights and obligations of the parties, executed between SPP and an entity seeking to become an SPP member.

NERC
The North American Electric Reliability Corporation or successor organizations.

Net Energy for Load
The load served by transmission facilities under the SPP Open Access Transmission Tariff. The electrical energy requirements of an electric system are defined as system net generation plus energy received from others, less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage at energy storage facilities.

Officers
The officers of SPP as elected by the Board of Directors. The Officers consist of the President and the Corporate Secretary, at a minimum. Any Officer must be independent of any Member organization.
**Organizational Group**
A group, other than the Board of Directors, comprising a committee or working group that is charged with specific responsibilities toward accomplishing SPP’s mission.

**Regional Criteria**
SPP planning and operating standards and procedures as approved by the Board of Directors.

**Regional Entity Trustees**
A governing body of SPP, independent of the Board of Directors, which specifically oversees SPP’s function as an ERO Regional Entity pursuant to the Delegation Agreement between SPP and the ERO.

**Regional Reliability Standards**
Electric reliability requirements submitted to the ERO by the Regional Entity Trustees; and once approved, implemented and enforced by SPP under authority as the Regional Entity.

**Registered Entity(ies)**
A bulk electric system owner, operator or user that is required to comply with ERO reliability standards pursuant to the Energy Policy Act of 2005.

**SPP**
Southwest Power Pool, Inc.

**SPP Regional Entity**
That part of SPP responsible for the delegated functions pursuant to the Delegation Agreement between SPP and the ERO.
SPP Compliance Monitoring and Enforcement Program
The program used by the North American Electric Reliability Corporation (‘‘NERC’’) and the Regional Entities to monitor, assess, and enforce compliance with Reliability Standards within the United States.

Staff
The technical and administrative staff of SPP as hired by the Officers to accomplish SPP’s mission.

Standards Development Team
An SPP Organizational Group assigned or choosing to develop an SPP Regional Reliability Standard for submission to the ERO for approval for enforcement.

Terminated Member
An entity that was a Signatory to the Membership Agreement but whose membership in SPP has been terminated under Section 4 of the Membership Agreement.

Transmission Owning Member
A Member that has placed more than 500 miles of non-radial facilities operated at or above 60 kV under the independent administration of SPP for the provision of regional transmission service as set forth in the Membership Agreement.

Transmission Using Member
A Member that does not meet the definition of a Transmission Owning Member.
8.7 Financial Obligation of Withdrawing Members

8.7.1 Existing Obligations

“Existing Obligations” are the following:

a. Member’s unpaid annual membership fee.

b. Member’s unpaid dues, assessments, and other amounts charged under Section 3.8 of the Membership Agreement, section 8.4 of the Bylaws, or otherwise under the Bylaws, plus the Member’s share of costs SPP customarily includes in such dues, assessments or other charges, but which as of the Termination Date SPP had not included in such dues, assessments or other charges.

c. Member’s share (computed in accordance with the Bylaws) of the entire principal amounts of all SPP Financial Obligations outstanding as of the Termination Date. “Financial Obligations” are all long-term (in excess of six (6) months) financial obligations of SPP, including but not limited to the following:

i. debts under all mortgages, loans, loan agreements, borrowings, promissory notes, bonds, and credit lines, under which SPP is obligated, including principal and interest;

ii. all payment obligations under equipment leases, financing leases, capital leases, real estate and office space leases, consulting contracts, and contracts for outsourced services;

iii. any unfunded liabilities of any SPP employee pension funds, whether or not liquidated or demanded; and

iv. the general and administrative overhead of SPP for a period of three (3) months.

d. Any costs, expenses or liabilities incurred by SPP directly due to the Termination, regardless of when incurred or payable, and including without limitation prepayment premiums or penalties arising under SPP Financial Obligations.
e. Member’s share (computed in accordance with the Bylaws) of all interest that will become due for payment with respect to all interest bearing Financial Obligations after the Termination Date and until the maturity of all Financial Obligations in accordance with their respective terms (“Future Interest”). In the event that a Financial Obligation carries a variable interest rate, the interest rate in effect at the Termination Date shall be used to calculate the applicable Future Interest. In determining the Member’s share of Future Interest, SPP shall take into account any reduction of Financial Obligations due to mitigation under this Section.

8.7.2 Computation of a Member’s Existing Obligations

For purposes of computing the Existing Obligations of any withdrawing or terminated Member in accordance with the Membership Agreement, such “Member’s share” is a percentage calculated as follows:

\[ A = 100 \left[ 0.25 \left(\frac{1}{N}\right) + 0.75 \left(\frac{B}{C}\right) \right] \]

Where:
- \( A \) = Member’s share (expressed as a percentage)
- \( N \) = Total number of Members
- \( B \) = The Member's previous year Net Energy for Load within SPP
- \( C \) = Total of factor B for all Members

The Finance Committee shall have the discretion to reduce the Existing Obligations of any withdrawing or Terminated Member, to reflect any SPP costs or expenses that may be mitigated in connection with such Member’s withdrawal or termination. In the event of consolidation of affiliate memberships or the transfer of membership from one corporate entity to another, whereby one entity remains a member of SPP, the withdrawal obligation for the departing company(ies) may be waived at SPP’s sole discretion.

8.7.3 Financial Obligations for Transmission Facilities

A Terminated Member shall remain financially responsible for all financial obligations incurred and costs allocated to its load for transmission
facilities approved prior to the Termination Date. Payments in fulfillment of any such obligations and allocated costs shall commence on the date that the costs of such transmission facilities are reflected in SPP’s generally applicable rates, unless SPP and the Terminated Member agree to an alternate date. Rights, obligations, and payments applicable to time periods prior to the Termination Date shall be honored by SPP and the Terminated Member. Fulfillment and performance of such rights and obligations, and rights and obligations regarding the use of such transmission facilities, shall be negotiated between SPP and the Terminated Member, and any disputes involving such rights and obligations shall be resolved in accordance with the dispute resolution procedures in the Bylaws and Membership Agreement.

8.7.4 Penalty Costs

A Terminated Member shall remain liable for its share of costs associated with penalties assessed against SPP by FERC, the FERC-approved Electric Reliability Organization, any Electric Reliability Organization-approved Regional Entity, or any other governmental or regulatory authority with jurisdiction over SPP that SPP incurs as a result of events that occurred prior to Member’s Termination Date but that SPP is unable to recover under the SPP OATT.
Southwest Power Pool, Inc.
CORPORATE GOVERNANCE COMMITTEE
Recommendation to the Board of Directors
October 29, 2013

Voting Process for Corporate Governance Committee Representatives

Background
The Corporate Governance Committee includes one representative from each member category, as selected by the members in that category. Vacancies are filled in the same manner.

Analysis
SPP’s Bylaws are very clear that for purposes of elections, Affiliate entities can cast only one vote, while for other purposes (ex: MOPC), each member company has one vote. For purposes of seating CGC representatives, the Bylaws state only that the members will select a representative, without regard to Affiliates.

The Corporate Governance Committee discussed the pros/cons of each approach and the potential impact, and determined that for purposes of seating representatives on the CGC, it would be better for Affiliates to have one vote.

Recommendation
The Corporate Governance Committee recommends approval of the Bylaws revision reflecting that for purposes of seating representatives on the CGC, Affiliates have one vote.

Approved: Corporate Governance Committee September 20, 2013 Via email unanimous

Action Requested: Approve recommendation
6.6 Corporate Governance Committee

The Corporate Governance Committee is responsible for the overall governance structure, including nominations, for the company in accordance with its scope as approved by the Board of Directors.

To the extent that the membership allows, the CGC shall be comprised of nine members. One representative shall be the President of SPP who will serve as the Chair; one representative shall be the Chairman of the Board, unless his/her position is under consideration, in which case the Vice Chairman of the Board; one representative shall be representative of and selected by investor owned utilities Members; one representative shall be representative of and selected by co-operatives Members; one representative shall be representative of and selected by municipals Members; one representative shall be representative of and selected by independent power producers/marketers Members; one representative shall be representative of and selected by state/federal power agencies Members; one representative shall be representative of and selected by alternative power/public interest Members; and one representative shall be representative of and selected by large/small retail Members.

Where a vacancy occurs with respect to a representative of a sector, the representatives from the appropriate sector will fill the vacancy. For purposes of selecting or removing representatives only, each group of Members with Affiliate Relationships shall be considered a single Member.

The CGC shall meet at least once per calendar year, and additionally as needed, provided that a quorum, as defined in these Bylaws, is present. The CGC shall report to the Board of Directors following each CGC meeting with respect to its activities and with such recommendations, as the CGC deems necessary.
Southwest Power Pool, Inc.

SPP STAFF

Recommendation to the Board of Directors

October 29, 2013

Regional Transmission Cost Allocation/Compliance Filing

Background
SPP filed revisions to its governing documents to address the treatment of regional transmission costs upon withdrawal from the organization.

Analysis
FERC accepted SPP’s approach to addressing regional transmission costs upon withdrawal (to be negotiated on a case-by-case basis). In its order the Commission required a compliance filing clarifying that the new provisions apply only to transmission owners. While the language did not specifically so state, it effectively did this.

SPP was granted an extension to make the compliance filing to November 1. The Membership received notice that the Board would be considering revisions to meet the Order. The necessary revisions occur in Section 8.7.3 of the Bylaws, and Section 4.3.3A of the Membership Agreement. Note the deletions in the Bylaws are simply duplicative of language in the Membership Agreement, which has not been altered.

Staff is making this recommendation due to time constraints between the Order and the compliance filing deadline, and because the Commission was explicit in what is required. The material was circulated to the Corporate Governance Committee via email.

Recommendation
Staff recommends approval of the revisions to the Bylaws and Membership Agreement to meet SPP’s compliance filing obligation as directed by FERC.

Circulated: Corporate Governance Committee October 22, 2013

Action Requested: Approve recommendation
BYLAWS

8.7    Financial Obligation of Withdrawing Members

8.7.1    Existing Obligations

“Existing Obligations” are the following:

a.    Member’s unpaid annual membership fee.

b.    Member’s unpaid dues, assessments, and other amounts charged under Section 3.8 of the Membership Agreement, section 8.4 of the Bylaws, or otherwise under the Bylaws, plus the Member’s share of costs SPP customarily includes in such dues, assessments or other charges, but which as of the Termination Date SPP had not included in such dues, assessments or other charges.

c.    Member’s share (computed in accordance with the Bylaws) of the entire principal amounts of all SPP Financial Obligations outstanding as of the Termination Date. “Financial Obligations” are all long-term (in excess of six (6) months) financial obligations of SPP, including but not limited to the following:

i.    debts under all mortgages, loans, loan agreements, borrowings, promissory notes, bonds, and credit lines, under which SPP is obligated, including principal and interest;

ii.   all payment obligations under equipment leases, financing leases, capital leases, real estate and office space leases, consulting contracts, and contracts for outsourced services;

iii.  any unfunded liabilities of any SPP employee pension funds, whether or not liquidated or demanded; and

iv.   the general and administrative overhead of SPP for a period of three (3) months.

d.    Any costs, expenses or liabilities incurred by SPP directly due to the Termination, regardless of when incurred or payable, and including without limitation prepayment premiums or penalties
arising under SPP Financial Obligations.

e. Member’s share (computed in accordance with the Bylaws) of all interest that will become due for payment with respect to all interest bearing Financial Obligations after the Termination Date and until the maturity of all Financial Obligations in accordance with their respective terms (“Future Interest”). In the event that a Financial Obligation carries a variable interest rate, the interest rate in effect at the Termination Date shall be used to calculate the applicable Future Interest. In determining the Member’s share of Future Interest, SPP shall take into account any reduction of Financial Obligations due to mitigation under this Section.

8.7.2 Computation of a Member’s Existing Obligations

For purposes of computing the Existing Obligations of any withdrawing or terminated Member in accordance with the Membership Agreement, such “Member’s share” is a percentage calculated as follows:

$$A = 100 \left[ 0.25(1/N) + 0.75(B/C) \right]$$

Where:

- $A$ = Member’s share (expressed as a percentage)
- $N$ = Total number of Members
- $B$ = The Member’s previous year Net Energy for Load within SPP
- $C$ = Total of factor $B$ for all Members

The Finance Committee shall have the discretion to reduce the Existing Obligations of any withdrawing or Terminated Member, to reflect any SPP costs or expenses that may be mitigated in connection with such Member’s withdrawal or termination. In the event of consolidation of affiliate memberships or the transfer of membership from one corporate entity to another, whereby one entity remains a member of SPP, the withdrawal obligation for the departing company(ies) may be waived at SPP’s sole discretion.

8.7.3 Financial Obligations for Transmission Facilities

To the extent that Section 4.3.3A of the Membership Agreement is applicable, Aa Terminated Member shall remain financially responsible for all
financial obligations incurred and costs allocated to its load for transmission facilities approved prior to the Termination Date. Payments in fulfillment of any such obligations and allocated costs shall commence on the date that the costs of such transmission facilities are reflected in SPP’s generally applicable rates, unless SPP and the Terminated Member agree to an alternate date. Rights, obligations, and payments applicable to time periods prior to the Termination Date shall be honored by SPP and the Terminated Member. Fulfillment and performance of such rights and obligations, and rights and obligations regarding the use of such transmission facilities, shall be negotiated between SPP and the Terminated Member, and any disputes involving such rights and obligations shall be resolved in accordance with the dispute resolution procedures in the Bylaws and Membership Agreement.

8.7.4 Penalty Costs

A Terminated Member shall remain liable for its share of costs associated with penalties assessed against SPP by FERC, the FERC-approved Electric Reliability Organization, any Electric Reliability Organization-approved Regional Entity, or any other governmental or regulatory authority with jurisdiction over SPP that SPP incurs as a result of events that occurred prior to Member’s Termination Date but that SPP is unable to recover under the SPP OATT.
MEMBERSHIP AGREEMENT

4.3 Obligations Upon Termination

4.3.1 Obligation to Hold Users Harmless

Transmission Customers taking service which involves facilities being withdrawn by a Transmission Owner from the functional control of SPP and where such service is under transmission contracts executed before the Termination Date shall continue to receive the same service for the remaining term of each such contract at the same rates, terms, and conditions that would have been applicable if the Termination or Partial Termination had not occurred. Transmission Owner agrees to continue providing service to such Transmission Customers in accordance with the preceding sentence, and shall receive revenues calculated in accordance with the OATT but no more in revenues for that service that if there had been no Termination or Partial Termination.

4.3.2 Obligation to Pay Current and Existing Obligations

(a) In the event of a Termination or Partial Termination, Member shall pay all obligations incurred under this Agreement at any time prior to the Termination Date. In addition, in order for SPP to recover a portion of certain debts and cost payable by SPP after the Termination Date as further specified in this Agreement, the Member shall pay all Existing Obligations (as defined herein) calculated as of the Termination Date. SPP shall make reasonable efforts to mitigate the Member’s Existing Obligations by commercially reasonable actions (such as prepayment of allocable debt, or investment of part or all of the Member’s payment in an interest-bearing instrument) and, in its discretion, may further discount the Member’s Existing Obligations to reflect any additional mitigation SPP determines it will achieve.

(b) “Existing Obligations” are all of the following and other obligations as may be set forth in the Bylaws from time to time;

i. Member’s unpaid annual membership fee,

ii. Member’s unpaid dues, assessments, and other amounts charged
under Section 3.8 of this Agreement, Section 8.4 of the Bylaws, or otherwise under the Bylaws, plus the Member’s share of costs SPP customarily includes in such dues, assessments or other charges, but which as of the Termination Date SPP had not included in such dues assessments or other charges.

iii. Member’s share (computed in accordance with the Bylaws) of the entire principal amounts of all SPP Financial Obligations outstanding as of the Termination Date. “Financial Obligations” are all long-term (in excess of six (6) months) financial obligations of SPP, including but not limited to the following:
   a. debts under all mortgages, loans, loan agreements, borrowings, promissory notes, bonds, and credit lines under which SPP is obligated, including principal and interest;
   b. all payment obligations under equipment leases, financing leases, capital leases, real estate and office space leases, consulting contracts, and contracts for outsourced services;
   c. any unfunded liabilities of any SPP employee pension funds, whether or not liquidated or demanded; and
   d. the general and administrative overhead of SPP for a period of three (3) months.

iv. Any costs, expenses or liabilities incurred by SPP directly due to the Termination, regardless of when incurred or payable, and including without limitation prepayment premiums or penalties arising under SPP Financial Obligations.

v. Member’s share (computed in accordance with the Bylaws) of all interest that will become due for payment with respect to all interest bearing Financial Obligations after the Termination Date and until the maturity of all Financial Obligations in accordance with their respective terms (“Future Interest”). In the event that a Financial Obligation carries a variable interest rate, the interest rate in effect at the Termination Date shall be used to calculate the
applicable Future Interest. In determining the Member’s share of Future Interest, SPP shall take into account any reduction of Financial Obligations due to mitigation under this Section.

(c) In the event of a Partial Termination, Existing Obligations shall first be calculated as though a Termination occurred, and the Member shall pay a percentage thereof as Existing Obligations due to the Partial Termination. Such percentage shall be the percentage reduction of the Net Energy for Load Ratio applicable to the Member resulting from the Partial Termination.

(d) In the event of a Termination or Partial Termination by a Member, the Member shall pay to SPP all costs SPP incurs to remove the Member’s facilities and/or load from SPP markets and operations. Such costs will be determined by SPP and shall include but not be limited to costs associated with modifying systems and databases, staff time, legal costs, and all costs of completing other tasks necessary to process the Member’s Termination. SPP will apply the Member’s withdrawal deposit, as specified in Section 4.2.1(b), to such costs, and any costs exceeding the withdrawal deposit shall be included in the invoice to the Member as discussed in Section 4.3.2(e) of this Agreement.

(e) SPP shall invoice Member for Existing Obligations within one month after the Termination Date, except that delay by SPP in issuing the invoice shall not diminish Member’s obligation to make timely payment. The invoice shall be due and payable no later than five (5) business days after issuance. Any amounts owed by SPP to the Member shall, solely at SPP’s election and in its discretion, be offset against the Member’s Existing Obligations or paid to the Member concurrently with issuance of the invoice.

(f) The Member acknowledges and agrees that Existing Obligations include amounts that SPP expects to accrue and that will become payable by SPP between the date of Member’s Notice of Termination and the Member’s Termination Date, and that no part of a payment of Existing Obligations
shall be refundable to the Member under any circumstances, including (except as provided in this Section with respect to mitigation or the execution of a new Membership Agreement by the Member after the Member’s Termination) any reduction of the Financial Obligations. Any disagreement as to the calculation of Existing Obligations shall be resolved in accordance with the dispute resolution procedures in the Bylaws. If, after Termination, the Member elects to re-join SPP and execute the Membership Agreement then in effect, SPP, in its sole discretion, may elect to credit a portion or all of the Member’s Existing Obligations paid to SPP upon the Member’s earlier Termination against any future payments owed by the Member to SPP.

4.3.3 Construction of Transmission Facilities

Any obligations relating to the construction of new facilities pursuant to an approved plan of SPP shall be negotiated between SPP and the Transmission Owner prior to the Termination Date so as to continue the Transmission Owner’s construction obligation for facilities for which SPP has issued a notification to construct to the Transmission Owner prior to the Termination Date. If such obligations cannot be resolved through negotiations, they shall be resolved in accordance with the dispute resolution procedures in the Bylaws and Membership Agreement.

4.3.3A Financial Obligations for Transmission Facilities

This Section 4.3.3A applies to any Terminated Member that was a Transmission Owner at the time it submitted its notice of intent to withdraw. ASuch Terminated Member shall remain financially responsible for all financial obligations incurred and costs allocated to its load for transmission facilities approved prior to the Termination Date. Payments in fulfillment of any such obligations and allocated costs shall commence on the date that the costs of such transmission facilities are reflected in SPP’s generally applicable rates, unless SPP and the Terminated Member agree to an alternate date. Rights, obligations, and payments applicable to time periods prior to the Termination Date shall be honored by SPP and the Terminated Member. Fulfillment and performance of
such rights and obligations, and rights and obligations regarding the use of such transmission facilities, shall be negotiated between SPP and the Terminated Member, and any disputes involving such rights and obligations shall be resolved in accordance with the dispute resolution procedures in the Bylaws and Membership Agreement.

4.3.4 Regulatory and Other Approvals or Procedures

Any Termination with respect to a Transmission Owner shall be subject to applicable federal and state law and regulatory approvals or procedures.
Southwest Power Pool, Inc.
FINANCE COMMITTEE
Recommendation to the Board of Directors
October 29, 2013

2014 Budget

Organizational Roster
The following persons are members of the Finance Committee:

- Harry Skilton, Director
- Larry Altenbaumer, Director
- Coleen Wells
- Mike Wise
- Sandra Bennett
- Kelly Harrison

Director
Kansas Electric Power Coop
Golden Spread Electric Coop
American Electric Power
Westar Energy

Background
Section 6.5 of the SPP Bylaws identifies establishment of annual and long-term budgets as a primary duty of the Finance Committee.

Analysis
SPP’s management proposed a 2014 budget to include expenditures as follows:

<table>
<thead>
<tr>
<th>Expenditure</th>
<th>$ millions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Expense (incl. dep. &amp; am.)</td>
<td>$200.7</td>
</tr>
<tr>
<td>Debt Repayment</td>
<td>$13.0</td>
</tr>
<tr>
<td>FERC Assessments</td>
<td>$15.3</td>
</tr>
<tr>
<td>Capital Expenditures</td>
<td>$37.1</td>
</tr>
</tbody>
</table>

SPP management utilized a “zero-based” budget approach to prepare the 2014 budget.

The most significant cost drivers for 2014 are the scheduled retirement of debt obtained to fund the development of the Integrated Marketplace and other capital expenditure projects, and increased support and maintenance for the Integrated Marketplace systems.

Recommendation
The Finance Committee recommends the SPP Board of Directors approve the 2014 SPP operating and capital budgets as submitted.

Approved: Finance Committee September 24, 2013

Action Requested: Approve Recommendation
2014 BUDGET

PREPARED BY ACCOUNTING DEPARTMENT
Hello.

The following presentation incorporates detailed financial information for SPP’s 2014 budget, along with additional context as to how investments in SPP result in value for the SPP region.

Total 2014 net revenue requirement (NRR) is expected to be $132.6 million and represents an increase of $10.8 million compared to the 2013 budget. The proposed administrative fee for 2014 is 38.1 cents as compared to 31.5 cents for 2013. Expenditures driving the growth in NRR include $5 million in new system maintenance agreements primarily associated with the implementation of the Integrated Marketplace, and approximately $5 million in salary and benefits as a result of a reduced vacancy rate and increased healthcare costs. The increase in the administrative fee is impacted by the above two items as well as lower peak load during 2013 in the SPP region.

Based on the proposed 2014 administrative fee, SPP will provide, by a conservative estimate, a 10-to-1 return to its members on the administrative fee. This analysis has been extensively vetted through SPP’s stakeholder groups, and SPP is confident that stakeholders see value both in what we do and how we do it. “How we do it” reflects our business model and differentiates us from other RTOs/ISOs.

Our budget enables SPP to:

1. Facilitate effective discussions that result in transmission expansion,
2. Lower overall costs by operating as a region,
3. Provide predictable and reliable operations of the bulk electrical system, and
4. Offer markets that are open, transparent, and deliver significant economic benefits.

The following documentation provides both qualitative and quantitative information to support this stewardship. In order to provide a more in-depth analysis, the 2014 – 2016 Budget is presented in three different views: by member value drivers, by resource utilization, and by division.

Thank you for your support as we continue to help our members work together in keeping the lights on, today, and in the future.

Regards,

Tom Dunn
Vice President, CFO
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I. 2014 Net Revenue Requirement

Southwest Power Pool (SPP) administers reliability coordination, wholesale energy markets, and transmission services for the benefit of electric utility operations in the SPP service region. As a Regional Transmission Organization, SPP is mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure, and a competitive wholesale electricity marketplace. In 2014, SPP will continue to gain momentum toward the realization of its strategic objectives of building a robust transmission system, developing efficient market processes, and creating and enhancing member value as outlined in its 2010 Strategic Plan.

Total 2014 operating expenses are expected to be $200.7 million and represent an increase of $38.1 million compared to the 2013 budget. Growth in operating expenses results primarily from implementation of the Integrated Marketplace ($5.4 million for maintenance of Integrated Marketplace software and $29.4 million for depreciation of the Integrated Marketplace asset), staffing related expense growth ($4.8 million), and interest on additional financing ($2.2 million).

SPP expects total savings of $4.2 million in 2014 due to various process improvements. The savings expected to be realized in 2014 due to operations staffing reductions is $1.9 million. The requested headcount for 2014 in the previous year’s budget was 618; the total headcount in the 2014 budget is 598, representing a net decline in headcount of 20 FTEs. Additionally, SPP expects to recognize savings in capital costs and non-staffing operating expenses of $1.8 million and $0.5 million, respectively. These initiatives and savings are discussed in further detail under Process Improvements in Section II.

The 2014 Net Revenue Requirement (NRR), a component for setting the administrative fee rate, is $132.6 million versus 2013 budget NRR of $121.8 million and 2013 forecast NRR of $120.8 million. The largest component of the increase in NRR is attributed to maintenance expense primarily associated with the Integrated Marketplace assets.

SPP projects transmission volume, another component used in setting the administrative fee, will decrease 3.5% to 348.2 million MWh in 2014 compared to the 2013 budget of 360.9 million MWh. Through July 2013, SPP’s members have experienced lower monthly peaks than those recorded in 2012. These reductions have been slightly offset by growth in point-to-point reservations primarily associated with moving renewable generation output out of the SPP.
region. Transmission volume of 348.2 million MWh represents a 2.8% decrease compared to the 2013 forecast of 358.1 million MWh.

SPP’s 2013 budget estimated the 2014 administrative cost/MWh to be 38.0¢/MWh based on an expected NRR of $141.4 million and load of 371.7 million MWh. SPP’s 2014 budget calculates an administrative cost of 38.1¢/MWh based on an expected NRR of $132.6 million and load of 348.2 million MWh.

The 2014 budget identifies capital expenditures totaling $61.8 million for 2014-2016, with $37.1 million expected to be incurred in 2014. These costs are not directly included in SPP’s Net Revenue Requirement; however, annual principal and interest payments (net of capitalized interest) for borrowings that fund these capital projects are a component of the Net Revenue Requirement. Integrated Marketplace and associated post-market projects represent $25.8 million of the capital expenditures projected for 2014-2016. Information Technology and Operations foundation projects represent $23.5 million during 2014-2016.

Components of 2014 Net Revenue Requirement and Administrative Fee

The following table shows the components and calculation of the administrative fee.

<table>
<thead>
<tr>
<th>Administrative Fee ($ millions)</th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
<th>2014 Prior Year Estimate (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Expenses</td>
<td>$162.6</td>
<td>$157.4</td>
<td>$200.7</td>
<td>$199.4</td>
</tr>
<tr>
<td>Debt Service (3)</td>
<td>12.7</td>
<td>12.7</td>
<td>13.0</td>
<td>23.0</td>
</tr>
<tr>
<td>Less: Depreciation/Amorization</td>
<td>(20.3)</td>
<td>(19.7)</td>
<td>(49.7)</td>
<td>(47.0)</td>
</tr>
<tr>
<td>Gross Revenue Requirement</td>
<td>$155.0</td>
<td>$150.4</td>
<td>$164.0</td>
<td>$175.4</td>
</tr>
<tr>
<td>Less: NERC revenue</td>
<td>(11.5)</td>
<td>(10.2)</td>
<td>(11.8)</td>
<td>(11.9)</td>
</tr>
<tr>
<td>FERC fee expense</td>
<td>(16.3)</td>
<td>(14.7)</td>
<td>(15.3)</td>
<td>(17.2)</td>
</tr>
<tr>
<td>Other Revenues</td>
<td>(5.4)</td>
<td>(4.7)</td>
<td>(4.2)</td>
<td>(4.8)</td>
</tr>
<tr>
<td>Net Revenue Requirement</td>
<td>$121.8</td>
<td>$120.8</td>
<td>$132.6</td>
<td>$141.4</td>
</tr>
<tr>
<td>Billing Determinant (MWh millions) (1)</td>
<td>360.9</td>
<td>358.1</td>
<td>348.2</td>
<td>371.7</td>
</tr>
<tr>
<td>Calculated Admin Fee/MWh</td>
<td>$0.338</td>
<td>$0.337</td>
<td>$0.381</td>
<td>$0.380</td>
</tr>
<tr>
<td>Proposed Admin Fee/MWh</td>
<td>$0.315</td>
<td>$0.315</td>
<td>$0.381</td>
<td>$0.370</td>
</tr>
<tr>
<td>Current Tariff Admin Fee Cap</td>
<td>$0.350</td>
<td>$0.350</td>
<td>$0.350</td>
<td>$0.350</td>
</tr>
</tbody>
</table>

(1) Defined as coincident peak for network service and capacity for point to point service in MWh.
(2) Refers to the 2014 estimate made during 2013 budget presentation.
(3) 2014 debt payments are $23 million with $10 million in current maturities funded with new debt proceeds.
II. Budget Overview

This budget document provides an overview and outlines details of the cost of services and components of the Net Revenue Requirement, which consists of the following:

- Operating expenses (sections III through V)
- Capital projects (section VI)
- Debt Service (section VII)

Operating expenses represent the largest component of the Net Revenue Requirement and consist of budgeted costs for ongoing operations. Operating expenses are presented in three different views:

- By contribution towards Member Value Statements (section III)
- By resource type (e.g. staffing, facilities) (section IV)
- By division (e.g. Operations, Engineering) (section V)

Capital projects are investments in long-term assets required for SPP to meet its strategic goals and operational requirements. These capital expenditures represent costs incurred to enhance or expand current systems and services, and to maintain existing capabilities.

The budget identifies 20 other capital projects impacting 2014, in addition to the Integrated Marketplace project and IT Foundation projects. Similar to prior years, over 42% of the budgeted capital expenditures is associated with the development and implementation of the Integrated Marketplace and the associated post-go-live projects. Capital projects are discussed in section VI.

Debt service costs are principal payments and interest expense related to various borrowings obtained to fund SPP’s capital expenditures. These include the Integrated Marketplace and construction of SPP’s new facilities, which was completed in July 2012. The term of different sources of funding is matched to the estimated useful life of these specific projects. Debt service is discussed in section VII.

Budget Guidance and Assumptions

Budget meetings were held in May and June 2013 to provide guidance in developing the 2014 budget. Under the direction of the executive team, each department director was tasked to create a zero-based budget for operating expenses. The following major drivers and assumptions were identified during the meetings:

Integrated Marketplace – The 2014 budget includes costs associated with the final phases of the Integrated Marketplace, which is set to launch on March 1, 2014.
consists of a group of interrelated projects and tasks that have been combined into a greater program. Given the expected annual net benefit of up to $100 million, this program has been identified as the highest priority by SPP’s Membership and Board of Directors. SPP’s Board of Directors initially approved a capital budget of $105 million in April 2011. In late 2012, cost projections began to trend upward primarily due to the cumulative impact of system component delays and related impacts to development, testing, and integration of downstream systems. Additionally, a FERC order received in October 2012 required changes to the market monitoring processes, which required additional hardware and software. In April 2013, the Board approved additional funding of $9.4 million for: 1) the extension of existing subject matter experts and testing resources required to meet the March 1, 2014 go-live date, and 2) the cost to bring market monitoring practices into compliance with FERC mandated requirements. The revised project budget of $115 million includes funding for the design, development and implementation of the following functions:

- Day-Ahead Market
- Transmission Congestion Rights
- Reliability Unit Commitment
- Real-Time Balancing Market
- Operating Reserve Market
- Consolidated Balancing Authority

The 2014 budget identifies capital expenditures and staffing for market-related functionality or enhancements that will be implemented after the March 2014 go-live date. The major initiatives contemplated in the 2014-2016 budget projections are as follows:

- Combined Cycle Functionality
- Regulation Compensation (FERC Order 755)
- Long Term TCRs (FERC required)
- AFC Granularity Changes for TSRs
- Market to Market (FERC required)

**FERC Order 1000** - Order 1000, which was issued by FERC in July 2011, has both regional and interregional planning implications.

From the regional perspective, the Order requires removal from regional tariffs of the federal right of first refusal (“ROFR”) for “green field” transmission construction. To comply with this requirement, SPP will implement a request for proposal (RFP) process to select qualified transmission owners for construction of approved transmission projects. On July 18, 2013, FERC conditionally accepted SPP’s Order 1000 regional compliance filing and set an effective date of
March 30, 2014. FERC also approved the competitive bidding process for regional transmission projects, which will apply to facilities approved by SPP’s Board of Directors beginning January 2015. SPP is required to initiate the process for reviewing applications from entities seeking to become qualified RFP participants in April 2014. SPP’s compliance filing proposed that SPP would retain the ROFR for “Byway” projects, which was the assumption in the 2013 budget planning for Order 1000; however, FERC did not approve this request. As a result, SPP expects the volume of work and costs associated with the competitive bidding process to be significantly higher than assumed in the 2013 budget.

By the end of 2013 SPP expects to add one position in the Legal and Regulatory division (originally approved in the 2013 budget) to manage Order 1000 RFP administration and to assist with the legal aspects of the RFP process. A second FTE was added in the 2014 budget to assist with the same functions as workload is anticipated to increase for review of qualified participants leading up to the April 2014 start date. Other costs budgeted in 2014 include RFP tracking software ($0.2 million) and consulting costs related to an Industry Expert Panel to be commissioned for the purpose of evaluating RFP responses beginning in 2015 ($1.3 million). SPP expects to recover the costs related to the RFP process from entities participating in the bidding process starting in 2015.

From the interregional perspective, the Order most notably increases information sharing and coordination between planning regions for interregional projects, and also calls for the development of joint planning studies between neighboring planning regions. For the 2013 budget, three engineering positions were added to ensure SPP’s compliance with the Order’s interregional aspects. As of August 2013, two of these positions have been filled, with the third position expected to be filled by the end of 2013.

**Strategic Outlook**

The 2010 Strategic Plan established a strategic direction for SPP, positioning SPP to fulfill its mission statement over the next decade and beyond. As a Regional Transmission Organization, SPP is mandated by FERC to ensure reliable supplies of power, adequate transmission structure, and a competitive wholesale marketplace. The strategic outlook for the energy industry drives SPP’s Strategic Plan, the ultimate goal of which is to ensure SPP fulfills its mandate. Below is the outlook per the Strategic Plan for the three main dimensions of the energy industry impacting SPP and its members in the development of strategic initiatives as determined by the Strategic Planning Committee (SPC).
Demand Growth

- The annual growth rate for electricity usage is projected to be 1.16% for 2010-2020 in SPP’s region; however, the actual rate is expected to fluctuate with the global economic cycles. SPP plans to accommodate these peaks and valleys in demand growth.
- Behind the meter generation resources by end-use customers, demand response, conservation and improved efficiencies are expected to impact demand at an increasingly growing rate.

Generation

- Many competing factors will impact the future mix of generation resources. SPP will remain informed on continuing developments and will incorporate flexibility and adaptability into future plans.
- Increased usage of renewable resources is becoming a significant factor in the generation mix, and necessitates the development of new tools and capabilities to plan for reliably integrating these resources into the grid.

Transmission

- Expansion of renewable resources will be a major factor impacting the transmission system, as many of these resources are located in areas not currently connected to the grid or will require significant capacity expansion.
- The introduction of new types of generation resources into the traditional mix will require greater inter-regional planning and coordination of the transmission system.
- More robust market capabilities will be required in the future, and regional grid operators will need to develop better mechanisms to extend benefits across the seams between market areas.
- Land acquisition and “right of way” issues are likely to continue becoming more complex and time-consuming.
- Reliability standards will likely grow in complexity and will require the ability to manage multiple simultaneous contingencies.

Alignment of 2014 Budget with SPP’s Strategic Plan

The Strategic Plan approved by the SPP Board of Directors in 2010 identifies three foundational strategies intended to leverage SPP’s capabilities and operational processes to ensure SPP fulfills its mission. The foundational strategies are the long-term, fundamental components of the SPP business model. As in previous years and consistent with the zero-based budgeting approach, SPP’s management completed an exercise in preparation for the 2014 budget in
which all business units set goals and initiatives linked to SPP’s strategic plan. These initiatives then went through a rigorous vetting process of prioritization and capacity measurement (i.e. determining adequate resource levels required to accomplish objectives without adversely impacting higher priority projects).

*Build a robust transmission system*

A robust transmission system includes an optimal mix of highways and byways, and minimizes future transmission constraints without over-investing in transmission capacity. A robust transmission system creates new value for SPP members and end users in the region. 2014 budget initiatives supporting this objective include:

- In 2014, Aggregate Transmission Service Studies (ATSS) and Generator Interconnection (GI) studies are expected to have stakeholder approval of process improvements that will expedite the study processes.
- Beginning in 2013, interregional aspects of Order 1000 have led SPP to work more closely with neighboring systems, which is expected to result in improved long-term planning processes and ensure the most cost-effective transmission expansions are approved and built, whether through interregional or regional solutions. In 2014 SPP will execute many of the provisions included in the
compliance filing. Working with neighboring entities, SPP will jointly evaluate potential interregional transmission solutions which would be more efficient and cost effective than regional transmission solutions.

- SPP’s R&D staff continues to research additional transmission planning approaches and tools to improve SPP’s ability to properly plan for future needs, which are projected to include non-dispatchable renewable energy resources in addition to the traditional dispatchable resources.
- ITP-10 and ITP-NT assessments will be performed in 2014.
- Engineering Division targets to conclude a high-priority Incremental Load Study in April 2014.

**Develop efficient market processes**

SPP’s strategy is to develop systems and tools to create effective, efficient, and transparent markets for its members. Members have indicated SPP has the objectivity and integrity needed to operate fair and open markets. The major initiative associated with this foundational strategy is the Integrated Marketplace. The activities surrounding the final phases of the development, testing and eventual launch of the Integrated Marketplace, as well as post-go-live projects, constitute a major portion of the 2014 budget.

- Creation of highly liquid and efficient Day Ahead and Real Time Balancing markets with Transmission Congestion Rights enables SPP members and customers greater utilization of the region’s diverse generating resources.
- The SPP market will allow reliability unit commitment performance on a region-wide basis, as well as economic unit commitment in the Day Ahead market.
- SPP will serve as the balancing authority for the SPP market region. In doing so, SPP will balance supply and demand for the market footprint and reduce individual participants’ balancing duties and the volume of operating reserves and energy, which currently must be provided by each individual entity.

**Create member value**

SPP creates and continually improves work processes to ensure efficiency and effectiveness. The following activities are examples:

- Reliability excellence: SPP maintains a quality-assurance program to monitor the operations staff and to continuously improve the operations processes and procedures. SPP has a rigorous operator training program and a process in place to track reliability related changes in NERC standards so that necessary training is provided to close any gaps.
• Enhance market monitoring tools: One of the 2014 goals of SPP’s Market Monitoring department is to implement and refine analytical and monitoring tools needed to effectively monitor the Integrated Marketplace. Improved monitoring will ensure the prices formed in the energy markets reliably reflect energy supply and demand, and will provide optimum value for all market participants.

• Continuous process improvement: SPP continues to expand its LEAN program with the purpose of development and facilitation of an organization-wide business improvement capability to improve the efficiency and effectiveness of the SPP work processes. The goal of this program is to eliminate or significantly reduce time spent for baseline jobs. Resulting time savings can then be allocated to support higher-value work or to manage staff attrition. The next section discusses how SPP has created value for its members through process improvements.

• Stakeholder communications and education: The Training department will enhance product delivery in response to demand for additional training in the areas of reliability, new and/or updated operator tools, and the Integrated Marketplace. This encompasses curriculum developments in the following areas: reliability tools training, scenario-based dispatch training, simulator learning experiences, and blended learning experiences for Integrated Marketplace, which includes preparation for parallel operations and go-live and post go-Live enhancements. The development and implementation of an Integrated Marketplace on-boarding curriculum will also be introduced in 2014.

Process Improvements
The requested headcount for 2014 in the previous year’s projection was 618. The total headcount in the 2014 budget is 598, which represents a net decline in headcount of 20 FTEs. The decline in headcount is attributable to 1) a net decrease in the scope of services required to provide member services (4 FTEs), and 2) a range of process improvements and management actions designed to increase efficiency and effectiveness and/or lower costs throughout the organization (16 FTEs).

The headcount projection for 2014 in the previous year’s budget was based on the best estimate of scope and associated headcount required to deliver planned services. Changes in scope come from three primary sources: 1) revised scope requirements by regulatory agencies changing the amount of work required for compliance (such as FERC Order 1000), 2) additions or elimination of services per member requests, 3) scope assumptions change as projects or initiatives become more mature and the projected support requirements become clearer.
The SPP staff is conscientious of the need for continuous business process improvements as a strategy to lower costs and increase the value of services delivered to SPP members. Several factors have contributed to SPP’s increased efficiency assumptions for the 2014 budget.

**Process Improvement Initiatives**

SPP has embraced continuous process improvement as a fundamental part of its business model and LEAN methodologies as the framework for empowering the staff to analyze work processes and create more efficient and effective business processes. The LEAN methodology helps cross-functional teams view processes that cross organizational boundaries as continuous end-to-end processes. This approach helps teams define the “desired future state” and helps identify the work required to further define better processes for implementation. As individual process improvements are implemented, small increments of work capacity are created. This additional capacity can either be allocated to valuable work currently left unattended, or in the aggregate, it allows redistribution of total work to enable lower headcount, thus leveraging turnover and retirement opportunities.

**Resource Planning Initiatives**

As SPP continues to utilize formal resource planning methodologies, the cross utilization of staff becomes a source of improved manpower utilization. As one example, the Integrated Marketplace-driven congestion hedging services initially required an engineer addition in the 2014 budget. This position was removed from the 2014 budget as a result of more granular analysis of manpower capabilities and assignments determining that required functions could be supported by existing qualified staff.

**Staff Cross-Training**

SPP has many highly specialized job functions. One source of staffing leverage is cross-training of staff in a functional area to perform multiple job functions. This allows the managers to adjust to dynamic shifts in workload from one specialty to another. Cross-training is a strategy that enables greater levels of staff utilization.

**Process Automation**

Automating manual processing steps can be a source of increased productivity, efficiency, and improved quality and reliability. Processes automation can be the result of creating “tools” developed by staff to automate repetitive tasks or may be the result of large projects to upgrade or implement software designed to support new or improved business processes. For example, SPP recently upgraded the ABRA Human Resources system. This upgrade enabled automation to support benefits enrollment and support, which was previously provided by an outside contractor. The automation reduces operating expenses by $40,000 per year.
**Learning Curve Impact**

Over the last several years, SPP increased staffing levels to develop and support new products and services. A large number of new hires were either new college graduates with limited experience, or experienced however new to SPP. In both cases, a “learning curve” is associated with gaining specific work experience. The new employees hired in the last few years have become more efficient and effective. The “learning curve effect” has resulted in the elimination of several planned staff additions required for Integrated Marketplace driven scope expansions. This is a result of current staff becoming more experienced and able to accommodate the expanded requirements.

**Management Challenge**

SPP management is cognizant of the need to reduce operating costs wherever feasible. This challenge has resulted in management reassessing workload in attempts to accomplish more work with the same number of resources, or to do the same amount of work with fewer resources. All of the above factors (LEAN, resource planning, staff cross-training, process automation, and learning curve impact) combined with accepting the challenge to increase efficiency, led to planned staff reductions in 2014 versus last year’s 2014 projections, even though the scope of services provided expanded in multiple areas of the organization. Implementation of the Integrated Marketplace is expected to bring both staffing challenges and opportunities; however, processes are expected to become more efficient and effective across the organization as staff maturation continues.

The following table shows the savings associated with the headcount reductions explained above, as well as other cost reduction initiatives.
An analysis of the work scope changes and process improvements impacting 2014 staffing compared to the projection in the previous year’s budget is shown in the following table.

### Business Process Improvements

<table>
<thead>
<tr>
<th>Cost Reduction Category</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Operations Staffing Cost Reductions</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Operation automation and desk consolidation – Tariff Admin and Interchange desks</td>
<td>$514</td>
<td>$534</td>
<td>standard practice</td>
</tr>
<tr>
<td>• Process improvements and increased efficiency (11) FTE in zero-based analysis</td>
<td>$1,430</td>
<td>standard practice</td>
<td>standard practice</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$1,944</td>
<td>$534</td>
<td>-</td>
</tr>
<tr>
<td><strong>Capital Non-Staffing Cost Reductions</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Year 3 of Oracle Unlimited Database Licensing Agreement</td>
<td>$1,802</td>
<td>standard practice</td>
<td>standard practice</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$1,802</td>
<td>standard practice</td>
<td>standard practice</td>
</tr>
<tr>
<td><strong>Operations Non-Staffing Cost Reductions</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Enhanced approach to SPP on-site Medical Clinic vs. baseline</td>
<td>$214</td>
<td>standard practice</td>
<td>standard practice</td>
</tr>
<tr>
<td>• ABRA upgrade eliminates Meloria contract support costs</td>
<td>$40</td>
<td>standard practice</td>
<td>standard practice</td>
</tr>
<tr>
<td>• Switched coffee service vendor for Corporate Campus</td>
<td>$60</td>
<td>standard practice</td>
<td>standard practice</td>
</tr>
<tr>
<td>• Meeting expense reduction strategy to leverage new Corporate Campus</td>
<td>$175</td>
<td>standard practice</td>
<td>standard practice</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$489</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Prior Years Cumulative Balance</strong> *</td>
<td></td>
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<td></td>
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<tr>
<td>$18,976</td>
<td></td>
<td></td>
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<tr>
<td><strong>Cumulative Value of Business Improvement Initiatives</strong></td>
<td></td>
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</tr>
<tr>
<td>$23,211</td>
<td>$23,745</td>
<td>$23,745</td>
<td></td>
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</tbody>
</table>

* includes $4.8 million in additional savings versus prior projections for 2013 Oracle unlimited database licensing fees due to increase in number of database cores actually deployed.
<table>
<thead>
<tr>
<th>2014 Headcount Analysis</th>
<th>Headcount change</th>
<th>Cumulative Headcount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated 2014 Headcount in 2013 Budget</td>
<td></td>
<td>618</td>
</tr>
</tbody>
</table>

**Scope Changes:**

- **Scope decreases in 2013:** -7
  - (2) Governmental Affairs positions not replaced
  - (1) Duplicate position
  - (1) RE Legal Clerk
  - (2) Stochastic Planning Engineer/BA (member direction)
  - (1) Interregional Coordination – Engineer III (Order 1000)

- **Scope decreases in 2014:** -3
  - (3) Stochastic Planning Engineer/BA (member direction)

- **Scope increases in 2014:** 6
  - (1) Engineer II – (GFA Carve Outs)
  - (1) Regulatory Analyst II (Order 1000)
  - (1) Manager, IT Acquisitions
  - (1) Sr Customer Relations Rep (Market Operations Focus) *
  - (1) Business Continuity Specialist *
  - (1) Business Process Improvement Project Manager *

**Net Impact of scope changes:** -4

**Process Improvements:**

- **Staff planning and management efficiencies:** -9
  - (1) Settlements Analyst
  - (1) Sr Compliance Analyst
  - (1) Market Monitor II
  - (1) Sr Accountant
  - (3) Operations Engineers (Ops Suppt/Market Ops)
  - (1) Manager, Operations Quality Assurance (RT Ops)
  - (1) Engineer/BA (Congestion Hedging)

- **Capacity creation initiatives (offset in 2014 scope increase above):** -3
  - (1) Operator position transferred to Customer Relations

- **(1) Customer Trainer moved as Business Continuity Specialist**

- **(1) PMO Project Manager moved to support LEAN focus**

**Deferred headcount additions:** -4

- **(2) IT Programmer Analysts deferred to 2015 **
- **(2) IT Programmer Analysts deferred to 2016 **

**Total process improvements:** -16

**Estimated 2014 Headcount in 2014 Budget:** -20

---

* These positions are offset by Capacity Creation initiatives and are net headcount neutral.

** Given the magnitude of systems change, increased workload is offset by planned productivity/efficiency gains. Work scope will be validated before making headcount additions in 2015 and 2016.
III. 2014 Budget: Member Value Statements (MVS) View

SPP aims to provide maximum value to its members and customers. SPP delivers significant value to its stakeholders in these four areas:

1. **Region-wide transmission planning** - SPP’s planning processes benefits members and the entire region by seeking to identify system limitations, developing transmission upgrade plans, and tracking project progress to ensure timely completion of system improvements.

2. **Operate open, transparent energy markets** - SPP’s markets are designed to ensure access to the least expensive reliably available energy from across the region.

3. **Operations and reliability services** - SPP provides one-stop shopping for use of the region’s transmission lines, which includes monitoring power flow throughout the footprint, managing congestion, and coordinating emergency response.

4. **Leveraged, centralized services** - SPP provides the following centralized services to its members:
   a. Training
   b. Tariff administration and scheduling services
   c. Regulatory services
   d. Compliance services
   e. Settlements

The value provided by SPP to its members in 2014 is estimated to be $1,345 million, as calculated by SPP’s Business Process Improvement department and previously presented to the Board of Directors and various Board committees.
SPP staff analyzed the objectives, functions and activities of the various business units to determine how each contributes to the member value statement. Certain groups that do not directly contribute to one of the value statements listed above, but rather provide corporate support to the organization as a whole, are grouped separately (i.e. IT, Corporate Services, Finance). The following chart illustrates the 2014 budgeted operating expenses by contribution to each member value statement:

### 2014 Operating Expenses Budget by MVS ($ millions)

<table>
<thead>
<tr>
<th></th>
<th>Open and Transparent Markets</th>
<th>Transmission Planning</th>
<th>Operations and Reliability</th>
<th>Centralized Leveraged Services</th>
<th>Corporate Support</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>$19.9</td>
<td>$12.9</td>
<td>$22.9</td>
<td>$9.6</td>
<td>$52.5</td>
</tr>
<tr>
<td>Operations</td>
<td>$3.9</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Engineering</td>
<td>$0.8</td>
<td>$11.8</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market Design</td>
<td>$1.0</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regulatory and Legal</td>
<td>$0.3</td>
<td></td>
<td>$2.2</td>
<td></td>
<td>$4.1</td>
</tr>
<tr>
<td>Comp, Comm, MMU</td>
<td>$2.1</td>
<td></td>
<td>$1.7</td>
<td>$0.4</td>
<td></td>
</tr>
<tr>
<td>Information Technology</td>
<td>$8.3</td>
<td>$0.7</td>
<td>$4.5</td>
<td>$3.2</td>
<td>$24.7</td>
</tr>
<tr>
<td>Process Integrity</td>
<td>$1.8</td>
<td>$0.8</td>
<td>$1.3</td>
<td>$3.8</td>
<td></td>
</tr>
<tr>
<td>Finance</td>
<td>$1.8</td>
<td></td>
<td>$1.2</td>
<td>$1.8</td>
<td></td>
</tr>
<tr>
<td>Corporate Services</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$6.4</td>
</tr>
<tr>
<td>Officers / Admin</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$11.3</td>
</tr>
</tbody>
</table>

**Transmission Planning**

SPP’s engineering function develops transmission plans for the SPP region, optimizing the effectiveness and efficiency of the transmission grid and enabling access to the lowest cost sources of power generation for all members, ensuring grid reliability. This incorporates
utilization of the Integrated Transmission Planning (ITP) process with guidance from and collaboration with the Transmission Working Group (TWG) and the Markets and Operations Policy Committee (MOPC). SPP identifies transmission expansion projects that benefit the region, and a regional cost-sharing methodology helps fund and build out the needed incremental transmission capacity. Transmission projects from both the balanced portfolio and the priority projects will be added to the transmission grid during the next several years to increase value to SPP members and their customers. The total value of region-wide transmission planning services provided to SPP members in 2014 is $160 million.

SPP’s collaborative, member-driven focus is reflected in its Integrated Transmission Planning (ITP) process, which balances the SPP footprint’s reliability, policy, and economic needs by assessing transmission needs. The ITP’s iterative three-year cycle includes 20-Year, 10-Year, and Near-Term assessments.

Members have indicated SPP’s consensus-building approach enables faster results and the ability to create effective regional cost allocation to aid construction of transmission.

The departments engaged in transmission planning activities are concentrated within SPP’s Engineering organization and include the following departments: Tariff Studies, Generation Interconnection Studies, Modeling, Economic Planning, Steady State Planning and Interregional Coordination.

2014 direct operating expenses related to transmission planning functions totals $12.9 million, comprised of:

- Staffing costs $9.2 million
- Consulting $2.1 million
- System maintenance $0.5 million
- Meetings and travel $0.4 million
- Administrative $0.4 million
- Regional State Committee (RSC) expenses $0.3 million
Operate open, transparent energy markets

SPP currently operates an Energy Imbalance Service (EIS) market, which produces net trade benefits to the region due to the reduced amount of short-term electricity production costs within the market footprint. This is a result of the regional security-constrained economic dispatch (SCED) implemented for the EIS market. In addition, SPP will implement a highly liquid and efficient Day Ahead and Real Time Balancing market with the launch of the Integrated Marketplace in 2014. The market will allow unit commitment performance on a region-wide basis. The estimated total member value of these markets is $315 million for 2014.

During the first quarter of 2014, SPP’s leadership and staff will be focused on getting all stakeholders to the Integrated Marketplace March 2014 finish line at the same time.

Subsequent to the go-live date, a series of projects will be underway to provide enhancements and new functionalities to the Integrated Marketplace.

The 2014 direct operating expenses that enable SPP to provide open and transparent market services to SPP members is $19.9 million, comprised of:

- Staffing costs $14.8 million
- System maintenance $2.8 million
- Consulting $2.0 million
- Meetings and travel $0.3 million

Although the launch of the Integrated Marketplace is a company-wide effort, certain departments within the Operations, Engineering, Market Design, and Compliance divisions are solely engaged in the Marketplace activities: Market Operations, Market Development and Analysis, Market Support, Market Monitoring and Congestion Hedging. A total of 52 employees in these departments are committed to providing market related services. In addition, a number of staff members in other departments (75) are also dedicated to Marketplace activities; the associated costs are included in the totals above.

Operations and Reliability Services

SPP provides member value through the provision of reliability coordination services. SPP’s operations data center monitors all activity on the bulk electrical energy grid 24 hours a day, 7
days per week. In addition to responding to outages and coordinating the response, SPP administers a planning function that assures the grid is highly reliable and minimizes disturbances, outages, duration of outages, and congestion. Members of RTOs have a lower probability of incurring avoidable blackouts than do standalone entities, and the duration of many disruptions is minimized.

Administered by SPP, the SPP Reserve Sharing Group (RSG) allows members to meet operating reserve requirements on a shared, pro-rata basis. The group risk-sharing approach provides significant economic synergy. As a result, less generation required to be held back by individual members, and allows for the freed-up generation capacity to be offered into the market to generate value for members. The total value of services to the aggregate SPP membership from the Reliability Coordination function and the Reserve Sharing Group for 2014 is estimated to be $775 million.

The 2014 direct operating budget for delivering member value related to operations and reliability services is $22.9 million, comprised of:

- Staffing costs $19.1 million
- Consulting $ 2.1 million
- System maintenance $ 1.4 million
- Meetings and travel $ 0.5 million

**Centralized and Leveraged Services**

Per member requests, SPP provides a series of centralized services to its members. Due to the specialization and the economies of scale involved, SPP is able to provide these services at a higher quality and lower unit cost to members than they could provide themselves. These centralized functions include: training, tariff administration and scheduling, regulatory services, compliance, and settlements. The annual
value of these services in 2014 to SPP members is estimated to be $95 million per year.

SPP is committed to providing centralized and leveraged services so SPP members benefit from expertise developed within SPP and realize significant savings by eliminating the need for these functions within their own organizations.

The 2014 direct operating expenses for Centralized Leveraged Services is $9.6 million, comprised of:

- **Staffing costs** $6.9 million
- **System maintenance** $1.7 million
- **Consulting** $0.5 million
- **Meetings and travel** $0.5 million

The following are the major centralized services provided by SPP:

**Compliance**
At the request of the Board Oversight Committee, the Compliance department will expand member outreach activities in 2014 to address identified compliance concerns. The department will continue developing a framework for improved outreach services throughout the region. This phased approach through 2016 includes marketing new services, providing an arena to engage member entities to share best practices and lessons learned, and reaching a unified approach to openly sharing information to facilitate compliance practice consistency. The Compliance department is comprised of a staff of 13 employees with a total budget of $1.7 million.

**Training**
The Training department continues to provide significant benefits to members and staff in 2014 by offering centralized training services in a host of formats, which translates to significant savings to SPP members in training development and consulting costs. In 2014, Customer Training will increase its product delivery in response to demand for additional reliability-related training, new and/or updated operator tools, and Integrated Marketplace training. The curriculum will include 1) development of new virtual modules, 2) enhancements to emergency response drills, 3) development of training on reliability tools, 4) development of scenario-based dispatch training simulator learning experiences, 5) five System Operations Conferences, and 6) development of blended learning experiences for the Integrated Marketplace, including an on-boarding curriculum that will launch in 2014. Due to member-hosted training events and increased utilization of computer-based training, travel and meeting expenses within the Training department are expected to decrease from both the 2013 forecast and budget. Of the
13 total Training staff, 8 are dedicated to Centralized Leveraged Services with a 2014 budget of $1.3 million.

**Regulatory Policy**

In 2014, the Regulatory department will continue to have responsibility for all regulatory filings related to the Integrated Marketplace protocols and tariff revisions, including filings necessary to implement the Readiness and Reversion Plans. The department will implement all tariffs and other governing document revisions, market monitoring revisions, and all necessary member/market participant regulatory approvals for participation in the Integrated Marketplace, including FERC market-based rate authority issues. With the exception of consulting for Order 1000, the department has eliminated consulting expenses in 2014, due to staff’s increased Integrated Marketplace expertise.

Regulatory department will continue to assist new members and market participants in obtaining appropriate regulatory approvals to participate in SPP’s Open Access Transmission Tariff (OATT) and manage the processes required to transition the facilities and services under the SPP tariff. The department has a staff of 14 employees with a total 2014 budget of $2.2 million.

**Settlements**

The two primary areas supported by this department are market settlements and transmission settlements. The market-settlements dedicated staff is included in the Market Operations member value category. The transmission settlements support includes performing daily pre-and post-validation settlements, publishing daily settlement statements, providing evidence documentation for SSAE-16 controls, on-boarding new market participants and transmission customers/owners, providing customer care administration and education, administering dispute resolution, and monitoring credit exposure.

Of the 25 total Settlements staff, 9 are dedicated to Centralized Leveraged Services with a 2014 budget of $4.4 million, which includes $1.7 million for maintenance expense related to Settlement systems.

**Information Technology**

Information Technology supports various systems throughout SPP. Services related to staff augmentation to support the Settlements system is allocated to Centralized Leveraged Services ($0.2 million). A staff of ten supports the systems ($1.2 million), with maintenance of $1.7 million.
Corporate Support

The various departments grouped under Corporate Support provide support services to the departments outlined above, which provide indirect value to SPP’s members. These departments and the corresponding 2014 budgets are shown below. Certain of these departments’ operating expenses related specifically to a member value statement are included in the operating budget of each member value statement as shown earlier, and excluded from the amounts below.

![2014 Corporate Support Budget ($ millions)](image-url)
IV. 2014 Budget: Resource Utilization View

SPP’s 2014 budget encompasses utilization of various resources in driving SPP to meet its strategic goals and organizational objectives. The chart below shows SPP’s resources and the corresponding 2014 budget amounts in comparison to 2013 budget and forecast.

![2014 Operating Expense Budget by Resource ($ millions)](image)

<table>
<thead>
<tr>
<th>Resource</th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Staffing</td>
<td>$77.4</td>
<td>$77.7</td>
<td>$82.2</td>
</tr>
<tr>
<td>Travel and Meetings</td>
<td>$4.2</td>
<td>$3.0</td>
<td>$3.1</td>
</tr>
<tr>
<td>Admin and Leasing</td>
<td>$5.4</td>
<td>$4.4</td>
<td>$4.9</td>
</tr>
<tr>
<td>Outside Services and Consulting</td>
<td>$16.3</td>
<td>$15.5</td>
<td>$14.6</td>
</tr>
<tr>
<td>Comm.</td>
<td>$4.4</td>
<td>$3.8</td>
<td>$3.9</td>
</tr>
<tr>
<td>Maint.</td>
<td>$10.5</td>
<td>$11.0</td>
<td>$15.9</td>
</tr>
</tbody>
</table>

**Staffing: Valuing Work at SPP**

SPP’s most valuable and significant resource, and driver of the single largest component of SPP’s annual operating budget, is its employees. Compensation-related expenses (including salary, benefits, and taxes) total $82.2 million and comprise 41% of the 2014 operating expenses budget, an increase of $4.8 million compared to the 2013 budget. The main factors leading to the increase in staffing costs in 2014 include changes in assumptions for the vacancy rate and merit increases, and anticipated increases in healthcare costs. The number of additional headcount proposed in the 2014 budget is two.
resulting in total staff of 598 employees versus 2013 approved headcount of 603 and 2014 prior projected headcount of 618.

**Vacancy Rate and Merit Assumptions**

Based on historical trends and expectations, previous year’s 2013 – 2015 projections included a vacancy factor of 6%. In previous years, staffing levels steadily increased primarily in anticipation of needs associated with the Integrated Marketplace, resulting in high vacancy rates as SPP was striving to hire a large number of employees in a short period of time. Although certain positions were eliminated during 2013, actual vacancy levels fluctuated between 3% and 4% throughout the year. By the end of 2013, headcount is expected to be within 2% of the projected 2013 level (584 of 596). SPP expects staff turnover in 2014 to be consistent with trends experienced in the past several years (2%). This equates to estimated turnover of 24 positions during the calendar year. Entering the year with 12 openings and assuming a 90-day period required to backfill open positions, SPP expects a vacancy rate of 2.7% in the first quarter, falling to less than 1% during the remainder of the year. The chart to the right illustrates expected staffing costs using various vacancy assumptions. For purposes of the 2014 budget, SPP utilized a 2% vacancy rate.

<table>
<thead>
<tr>
<th>Salary Expense with Various Vacancy %</th>
</tr>
</thead>
<tbody>
<tr>
<td>1% Vacancy</td>
</tr>
<tr>
<td>2% Vacancy</td>
</tr>
<tr>
<td>3% Vacancy</td>
</tr>
<tr>
<td>4% Vacancy</td>
</tr>
<tr>
<td>5% Vacancy</td>
</tr>
<tr>
<td>6% Vacancy</td>
</tr>
</tbody>
</table>

The Human Resource Committee recommended an overall merit increase of 2.4% for 2014 based on the CPI inflation rate and feedback from SPP members, which also contributes to higher salary expenses in 2014 (merit increase was budgeted at 2.0% in 2013). The promotion pool remained constant at 0.75%.

**Healthcare Costs**

The net cost of the self-funded medical plan in the 2014 budget is $4.6 million, an increase of 26% or $0.96 million compared to the 2013 budget, and 18% or $0.69 million compared to the 2013 forecast. Part of this increase is due to the lower vacancy in 2014 as compared to 2013; however, the majority is due to the increase in medical claims SPP has experienced since late 2012. This upward trend is expected to continue throughout 2014, resulting in higher healthcare expenses.

Approximately 91% of employees participate in the medical plan. The number of participants in 2014 is estimated to be 541, compared to an average of 528 employees in 2013. Total gross claims are estimated to be $4.8 million, compared to a forecast of $4.0 million in 2013. SPP pays fees to the insurance provider to cover administrative costs and insure against excessive losses at both the participant and corporate level. These fees are estimated to be $0.97 million
and $0.91 million in 2014 and 2013, respectively. By increasing the deductible on per participant losses, SPP plans to mitigate the increase in fees that would normally be incurred due to the growth in claims. Employee contributions to the medical plan offset the overall cost and are estimated to be $1.2 million in 2014, compared to a forecast of $1.1 million in 2013. The net cost of the medical plan to SPP per participant is expected to be $713/month, compared to $645/month in 2013 mainly due to the increase in claims. SPP’s Human Resource Committee targets to maintain an 80/20 cost ratio between employer and employee. The following table illustrates total healthcare costs using various cost ratio percentages.

### Healthcare Costs ($ millions)

<table>
<thead>
<tr>
<th>Cost Ratio</th>
<th>80/20</th>
<th>75/25</th>
<th>70/30</th>
<th>60/40</th>
</tr>
</thead>
<tbody>
<tr>
<td>Employer</td>
<td>$4.6</td>
<td>$4.4</td>
<td>$4.1</td>
<td>$3.5</td>
</tr>
<tr>
<td>Employee</td>
<td>$1.2</td>
<td>$1.5</td>
<td>$1.7</td>
<td>$2.3</td>
</tr>
<tr>
<td>Total</td>
<td>$5.8</td>
<td>$5.8</td>
<td>$5.8</td>
<td>$5.8</td>
</tr>
</tbody>
</table>

### Staffing Levels

SPP’s management continuously assesses and evaluates SPP’s staffing levels across all areas of the organization. SPP’s approved headcount was reduced to 596 during 2013 from a budget-approved level of 603. These reductions primarily resulted from restructuring efforts to absorb responsibilities as positions became vacant due to turnover or internal transfers, and changes in member requests for services. Similarly, the 2014 headcount forecast was 618 during the 2013 budget cycle.

During the zero-based budget process used during the 2014 budget cycle, SPP’s management team determined staffing levels required to perform SPP’s functions could be accomplished at a
staffing level of 598, which is 20 positions below the previous forecast. Management continues to monitor staff capabilities and capacity versus staffing levels.

Incremental staffing for the Stochastic Planning initiative was removed from the 2013 budget after the Markets and Operations Policy Committee (MOPC) withdrew the project from consideration in early 2013. Four IT positions originally planned for 2014 were deferred until 2015-2016. The IT Applications department will evaluate the need for additional staffing subsequent to the Integrated Marketplace implementation. Operations Support department seeks to gain efficiencies through software and process improvements, and increased utilization of “smart” tools developed by the Operations Engineering staff. Recognizing these efficiencies, Operations Support is confident of their ability to absorb incremental workload from all phases of the Market-to-Market initiative, and has eliminated three positions previously expected for 2014. Various other areas have also withdrawn positions previously anticipated for 2014 including Finance, Compliance, and Communications.

The table below shows the staff numbers by executive division:

<table>
<thead>
<tr>
<th>Headcount by Division</th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations</td>
<td>158</td>
<td>157</td>
<td>157</td>
</tr>
<tr>
<td>Information Technology</td>
<td>143</td>
<td>144</td>
<td>144</td>
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<tr>
<td>Engineering</td>
<td>81</td>
<td>78</td>
<td>79</td>
</tr>
<tr>
<td>Process Integrity</td>
<td>47</td>
<td>47</td>
<td>47</td>
</tr>
<tr>
<td>Finance</td>
<td>40</td>
<td>39</td>
<td>39</td>
</tr>
<tr>
<td>Compliance, Communications, and MMU</td>
<td>31</td>
<td>30</td>
<td>30</td>
</tr>
<tr>
<td>Corporate Services</td>
<td>29</td>
<td>29</td>
<td>29</td>
</tr>
<tr>
<td>Regulatory Policy and Legal</td>
<td>25</td>
<td>25</td>
<td>26</td>
</tr>
<tr>
<td>Officers</td>
<td>11</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Market Development</td>
<td>6</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>Subtotal</td>
<td>571</td>
<td>565</td>
<td>567</td>
</tr>
<tr>
<td>Regional Entity</td>
<td>32</td>
<td>31</td>
<td>31</td>
</tr>
<tr>
<td><strong>Total Headcount</strong></td>
<td><strong>603</strong></td>
<td><strong>596</strong></td>
<td><strong>598</strong></td>
</tr>
</tbody>
</table>

SPP strives to attract and retain a highly educated and skilled employee base to provide the highest level of service and value for its members. Compensation and benefits are regularly monitored to ensure SPP remains a competitive and attractive employer. SPP administers an in-house Engineer in Rotation program, which seeks the most talented Engineering graduates for an expansive training program. A rotating staff of six engineers gain experience through on-the-job training, and are placed in permanent roles as positions become available through normal employee turnover.
The staffing budget for 2014 includes funding for staff compensation (base salary, performance compensation, and overtime pay), benefits and payroll taxes, relocation, and tuition reimbursement. The base salary budget includes a merit increase of 2.4% and promotion increase of 0.75%, which is a pool of funds for company-wide promotions overseen by the Human Resources department. Performance compensation is budgeted at the target level of 15.0% of base salary and is paid in February of the following year.

The budget for benefits and payroll taxes includes medical, dental, and life insurance benefits, retirement plan contributions, relocation expenses, and payroll taxes. Insurance benefits are budgeted based on projected per participant costs. Funding for 401(k) matching contribution is estimated at 4% of the salary expense based on recent company trends. Below is a breakdown of various employee benefits and taxes:

<table>
<thead>
<tr>
<th>Benefits and Payroll Taxes ($ millions)</th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Performance Compensation</td>
<td>$7.6</td>
<td>$7.6</td>
<td>$8.4</td>
</tr>
<tr>
<td>Medical Benefits</td>
<td>3.7</td>
<td>4.0</td>
<td>4.6</td>
</tr>
<tr>
<td>Dental Benefits</td>
<td>0.5</td>
<td>0.4</td>
<td>0.4</td>
</tr>
<tr>
<td>Life Insurance Benefits</td>
<td>0.4</td>
<td>0.2</td>
<td>0.2</td>
</tr>
<tr>
<td>Retirement Plans (401k and Pension)</td>
<td>6.9</td>
<td>6.8</td>
<td>7.3</td>
</tr>
<tr>
<td>Payroll Taxes</td>
<td>4.4</td>
<td>4.2</td>
<td>4.7</td>
</tr>
<tr>
<td>Continuing Education</td>
<td>0.9</td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>Other Employee Benefits</td>
<td>0.6</td>
<td>0.3</td>
<td>0.3</td>
</tr>
<tr>
<td><strong>Total Benefits and Payroll Taxes</strong></td>
<td><strong>$25.0</strong></td>
<td><strong>$24.4</strong></td>
<td><strong>$27.0</strong></td>
</tr>
</tbody>
</table>

**Outside Services**

Outside services consist of third-party expertise to assist SPP in deploying various services, providing legal representation and advice, and satisfying audit requirements. Outside service expenses are estimated to be $14.6 million in 2014 representing a decrease of $1.7 million compared to the 2013 budget, and comprising 12% of the total operating expenses (excluding FERC fees, depreciation and interest).

Outside services expenses have decreased from the 2013 budget in various areas, with offsetting minimal increases in other areas. As the Integrated Marketplace project nears completion, the demand for staff augmentation related to Integrated Marketplace has
decreased by $0.9 million in the following departments: Training ($0.2 million), Market Design ($0.3 million), Market Monitoring ($0.2 million), and Operations ($0.2 million).

Outside legal counsel is utilized for various litigation matters throughout the year. The Legal department has made conscious efforts to internalize work previously done by outside FERC counsel. Legal staff currently responds to 60-75% of all FERC requests, excluding Integrated Marketplace filings. Much of the work brought in-house was previously performed by highly specialized outside counsel, which demanded premium rates. Reducing reliance on outside legal expertise results in considerable cost savings. The decrease in 2014 versus the 2013 budget is $0.7 million.

<table>
<thead>
<tr>
<th>Outside Services by Division ($ millions)</th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Information Technology</td>
<td>$3.7</td>
<td>$3.9</td>
<td>$3.9</td>
</tr>
<tr>
<td>Regulatory Policy and Legal</td>
<td>$3.7</td>
<td>$3.2</td>
<td>$2.7</td>
</tr>
<tr>
<td>Engineering</td>
<td>$2.0</td>
<td>$1.7</td>
<td>$2.1</td>
</tr>
<tr>
<td>Regional Entity</td>
<td>$1.5</td>
<td>$1.0</td>
<td>$1.5</td>
</tr>
<tr>
<td>Process Integrity</td>
<td>$1.2</td>
<td>$1.3</td>
<td>$1.2</td>
</tr>
<tr>
<td>Operations</td>
<td>$0.8</td>
<td>$1.2</td>
<td>$0.9</td>
</tr>
<tr>
<td>Officer and Admin</td>
<td>$0.8</td>
<td>$1.4</td>
<td>$0.8</td>
</tr>
<tr>
<td>Corporate Services</td>
<td>$1.2</td>
<td>$0.8</td>
<td>$0.8</td>
</tr>
<tr>
<td>Finance</td>
<td>$0.5</td>
<td>$0.2</td>
<td>$0.2</td>
</tr>
<tr>
<td>Compliance, Communications, and MMU</td>
<td>$0.3</td>
<td>$0.2</td>
<td>$0.2</td>
</tr>
<tr>
<td>Market Development and Analysis</td>
<td>$0.3</td>
<td>$0.3</td>
<td>$0.0</td>
</tr>
<tr>
<td>Total Outside Services Expense</td>
<td>$16.0</td>
<td>$15.3</td>
<td>$14.3</td>
</tr>
</tbody>
</table>

The Regulatory department has progressively worked to integrate consulting knowledge in-house and therefore eliminate the need for outside consultants. These efforts have resulted in noticeable savings in the 2014 budget. SPP’s Regulatory staff will assume responsibilities for coordinating efforts within the Integrated Marketplace work-stream with other areas within SPP, resolve complex tariff matters such as the Z2 crediting project, and carry out various other tariff filings. The Regulatory work-stream coordinates and analyzes the impact of future regulatory changes with the market design and any appropriate work-streams, and is responsible for all of the Integrated Marketplace filings,
tariff language, and coordination with the other work-streams (i.e. Market Systems, Readiness, Ops, etc.). The decrease versus the 2013 budget is $0.5 million.

The 2013 Corporate Services budget included $0.2 million to incorporate an on-site medical clinic. As SPP remains focused on maintaining a healthy workplace, a fitness kiosk has been included in the 2014 budget in lieu of the full-scale medical clinic at a fraction of the original cost.

The above reductions from 2013 are partially offset by increases in various areas. In 2013, consulting engagements for Project Managers were assumed dedicated to the Integrated Marketplace and associated costs were included in capital expenditures instead of the operating budget. As responsibilities were assigned throughout the year, most of the external consultants were assigned to general project management duties not associated with the Integrated Marketplace or other capital projects, causing 2013 expenses to exceed the budget. The 2014 Project Manager resource-demand requirements exceed the internal staff capacity, and contractors will be engaged for staff augmentation. Projects associated with the Integrated Marketplace are driving the resource demands on internal staff. Proficiency gains, coupled with the projected completion date of the Integrated Marketplace, are expected to result in a decrease in the demand for Project Managers in the fourth quarter of 2014. As a result, staff augmentation was incorporated into the 2014 budget instead of requesting additional permanent staff, and outside services expenses have increased over the 2013 budget by $0.3 million.

In the IT department, the 2014 OATI budget has increased over 2013 due to additional services supporting the Integrated Marketplace and new initiatives for improved reliability ($0.1 million). These increases include changes related to the Integrated Marketplace for Regional Transmission Organization Scheduling System, Reserve Sharing System and related interfaces, and OATI webTag. The implementation of OATI Premium Support provides an additional level of support including a dedicated customer-service support-line. The level of network redundancy will be upgraded by adding a business-to-business VPN, which will improve the functionality of the network in the event of circuit issues.

Consultants are also engaged to perform wind forecasting analysis. These costs increased over 2013 due to efforts involved in sharing wind-forecast data with members, and costs associated with adding new wind farms to the 2014 analysis. The increase over the 2013 budget is $0.1 million.

The Systems Operations department budget includes fees for the Interchange Distribution Calculation (IDC) tool, which is a web-based service to assist SPP in providing reliability services throughout the entire region. Since NERC ceased funding of the tool, each Reliability
Coordinator (RC) is responsible for its administration within the region based on load-ratio share within the RC footprint. SPP's 2014 fee for the IDC tool is expected to increase by $0.3 million from 2013.

**Maintenance**

Maintenance expense includes facilities maintenance, and all hardware and software support and maintenance. These expenses are expected to increase significantly versus both 2013 budget and forecast primarily due to new maintenance support agreements in 2014 related to the Integrated Marketplace.

<table>
<thead>
<tr>
<th>Maintenance Expense ($ millions)</th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
<th>Prior 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>General Plant Maintenance</td>
<td>$ 0.8</td>
<td>$ 0.8</td>
<td>$ 0.7</td>
<td>$ 0.8</td>
</tr>
<tr>
<td>IT Equipment</td>
<td>$ 9.7</td>
<td>$ 10.2</td>
<td>$ 15.2</td>
<td>$ 14.5</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 10.5</strong></td>
<td><strong>$ 11.0</strong></td>
<td><strong>$ 15.9</strong></td>
<td><strong>$ 15.3</strong></td>
</tr>
</tbody>
</table>

IT maintenance is associated with hardware and software currently supported and expected to be utilized over the next three years. IT maintenance expenses are projected to increase $5.5 million and $5.0 million compared to the 2013 budget and 2013 forecast, respectively, however only $0.7 million over the prior 2014 forecast. Approximately $2.8 million of the 2014 budget is for software and systems maintenance related to market operations, driven by the launch of Integrated Marketplace necessitating maintenance on system software, plus additional servers and associated software. Maintenance must be in place on all system hardware and software to obtain the latest releases or upgrades, and to provide vendor support for new functionality and features, assistance in diagnosing issues, and answering configuration questions.

Maintenance related to IT foundation increased approximately $1.8 million compared to the 2013 budget and forecast, mainly due to server, data warehouse, and network related equipment upgrades.

<table>
<thead>
<tr>
<th>Maintenance Expense ($ millions)</th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
<th>Prior 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Support-IT Foundation</td>
<td>$ 6.0</td>
<td>$ 6.0</td>
<td>$ 7.8</td>
<td>$ 5.9</td>
</tr>
<tr>
<td>Market</td>
<td>$ 0.7</td>
<td>$ 0.9</td>
<td>$ 2.8</td>
<td>$ 4.1</td>
</tr>
<tr>
<td>Support-Project/Other</td>
<td>$ 0.3</td>
<td>$ 0.6</td>
<td>$ 0.9</td>
<td>$ 0.7</td>
</tr>
<tr>
<td>General Plant Maintenance</td>
<td>$ 0.8</td>
<td>$ 0.8</td>
<td>$ 0.7</td>
<td>$ 0.8</td>
</tr>
<tr>
<td>Transmission</td>
<td>$ 0.5</td>
<td>$ 0.5</td>
<td>$ 0.5</td>
<td>$ 0.5</td>
</tr>
<tr>
<td>Leveraged Services</td>
<td>$ 1.0</td>
<td>$ 1.0</td>
<td>$ 1.7</td>
<td>$ 2.0</td>
</tr>
<tr>
<td>Reliability</td>
<td>$ 1.3</td>
<td>$ 1.2</td>
<td>$ 1.4</td>
<td>$ 1.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$ 10.5</strong></td>
<td><strong>$ 11.0</strong></td>
<td><strong>$ 15.9</strong></td>
<td><strong>$ 15.3</strong></td>
</tr>
</tbody>
</table>

Other maintenance costs include various facility expenses such as janitorial expense, landscape maintenance, and preventive maintenance. The facilities maintenance budget for 2013 was
based upon a combination of industry best practices and guidelines, input from the architects and engineers involved with the Corporate Campus construction project, and actual pricing for known services. The 2014 budget was established based on historical costs of operating the facility for 12 months. The facilities maintenance budget for 2014 is $0.7 million versus 2013 budget and forecast of $0.8 million.

**Administrative and Leasing Expenses**

Administrative and leasing expenses are expected to decrease by $0.5 million in 2014 compared to the 2013 budget. Utilities for the 2013 budget were estimated based on guidance received from outside experts working on the new campus project. After having occupied the campus for a full year, more comprehensive data was available to better estimate utilities expenses for the 2014 budget, which is $0.7 million under the 2013 budget. The budget for office expenses in 2014 also reflects a decrease of $0.2 million, primarily related to savings resulting from consolidating employees on one campus. Leasing expenses decreased by $0.2 million in 2014. When SPP’s lease on the additional office space expired in April 2013, employees and consultants were relocated to the corporate campus in order to accommodate the testing and parallel operations phases of the Integrated Marketplace. The decreases are offset by a rise in small equipment expenses, which is driven by the decision to increase the capitalization threshold in 2014 and primarily impacts desktop and laptop computer purchases. During 2013, SPP analyzed the number and dollar amount of capitalized asset additions and determined over

<table>
<thead>
<tr>
<th>Administrative &amp; Leasing ($ millions)</th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Property Tax</td>
<td>$1.1</td>
<td>$1.1</td>
<td>$1.1</td>
</tr>
<tr>
<td>Insurance</td>
<td>$1.0</td>
<td>$1.0</td>
<td>$1.1</td>
</tr>
<tr>
<td>Utilities</td>
<td>$1.5</td>
<td>$0.7</td>
<td>$0.8</td>
</tr>
<tr>
<td>Dues &amp; Donations</td>
<td>$0.6</td>
<td>$0.6</td>
<td>$0.7</td>
</tr>
<tr>
<td>Equipment</td>
<td>$0.2</td>
<td>$0.3</td>
<td>$0.6</td>
</tr>
<tr>
<td>Office</td>
<td>$0.6</td>
<td>$0.4</td>
<td>$0.4</td>
</tr>
<tr>
<td>Leases</td>
<td>$0.4</td>
<td>$0.2</td>
<td>$0.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$5.4</strong></td>
<td><strong>$4.4</strong></td>
<td><strong>$4.9</strong></td>
</tr>
</tbody>
</table>
45% of the number of assets capitalized were less than $5,000 in acquisition cost. These same assets comprised less than 1% of the total dollar amount of assets capitalized. Given the administrative costs associated with tagging, recording, tracking, etc., a more cost-effective and resource-efficient approach was considered, and the decision was made to raise the capitalization threshold from $1,000 to $5,000 beginning in 2014. The impact of this change in 2014 is an increase to operating expense of $0.3 million. Slight increases were also reflected in insurance, dues, and property taxes ($0.1 million each).

During 2013, SPP worked extensively with the Arkansas Public Service Commission (APSC) to modify the methodology for assessing property for taxing purposes. SPP successfully persuaded the APSC to take into consideration that software assets were utilized outside of the state of Arkansas to deliver reliable low-cost electricity and therefore only the value of the software providing reliable low-cost electricity within Arkansas should be subject to Arkansas personal property taxes. Commencing with the 2012 year-end assets, values were assessed in 2013 using the new methodology. The bill for the 2013 assessment will be payable in 2014 and represents an estimated net savings of approximately $1.0 million in comparison to the previous methodology.

**Communications**

Communications expense includes all expenditures related to SPP’s internal and external networks and telecommunications. In 2014, network communication expenses are expected to increase slightly over the current 2013 forecast ($0.1 million). This increase is primarily due to additional capacity required for the Integrated Marketplace. Other factors contributing to the increase are
expected increases in NERCnet expenses due to a change in provider (initiated by NERC), addition of a SERC hotline to provide a direct link for critical reliability issues, and an increase in OATI frame relay costs to increase capacity arising from bandwidth saturation.

SPP will realize cost savings in cellular communications expenses in 2014 by either eliminating or reducing employee reimbursements for cellular services, and significantly reducing the number of company provided phones and aircards. The reduction in such expenses compared to 2013 is estimated to be approximately $0.2 million.

**Travel and Meetings**

Travel and meetings expenses are expected to decrease by $1.1 million in 2014 as compared to the 2013 budget; however, the 2014 expenses are more closely aligned with the 2013 forecast. The 2013 budget assumed meeting expenses of $0.2 million and travel of $0.2 million for member outreach workshops for the Integrated Marketplace. At members’ requests, many of the workshops were performed via computer-based training (CBT) and/or net conferences, thus leading to considerable cost savings in 2013. The 2014 budget includes a minimal amount of travel and meeting expenses for Integrated Marketplace member outreach.

The decrease is also partially attributable to increased usage of SPP’s corporate facilities for various meetings, as well as utilization of member facilities, which results in significant savings compared to hotel or conference space rentals. In efforts to reduce travel and meeting expenses, SPP encourages all organizational groups to include Little Rock in the rotation for working group meetings.
V. 2014 Budget: Division View

The 2014 operating budgets of the ten divisions are shown below.

**Operations**

The Operations group administers SPP’s Tariff and performs reliability coordination throughout SPP’s footprint. The department has a total budget of $21.6 million for 2014, including staff of 157. The group achieves this strategically important goal with a highly-trained staff of professionals in the following departments:
• Systems Operations: This department is responsible for ensuring 24/7 monitoring of the bulk grid in the SPP region. During 2013, process improvements and automation resulted in the combination of tariff and interchange functions. As a result, operator resources became available for utilization in Integrated Marketplace and Centralized Balancing Authority (CBA) functions, which eliminated the need for the incremental resources previously forecasted for 2014. At the Integrated Marketplace launch in 2014, Systems Operations will transition to the role of CBA. Outside consultant will assist throughout the transition to the go-live date; however, SPP will utilize operators’ expertise thereafter and eliminate the need for further consulting services. This department has 74 positions, including a department director, four managers, and seven shift supervisors.

• Markets Administration: This group plays an integral role in the launch of the Integrated Marketplace. The group is comprised of a staff of 19 employees and is divided into two main groups which reflect the fundamental structure of real-time and day-ahead markets.

• Operations Support: This group provides support services to the Operations division in areas such as outage coordination, load forecasting, modeling and data validation, and market data and registration, as well as extensive customer interaction and support. As a result of the Integrated Marketplace launch in 2014, Operations Support expects its workload to increase significantly due to inquiries and disputes resulting from an increased number of market participants, as well as the increased complexity of market models and calculations. This group has a staff of 56 employees, with no additional headcount anticipated for 2014 and beyond.

• Operations Analysis and Performance: This group’s main goal in 2014 is to ensure operators and support staff are properly trained and prepared for Integrated
Marketplace go-live. This group has a staff of 8 employees, with the primary goal of training SPP’s operators to ensure compliance with NERC standards.

**Engineering**

The Engineering division’s mission is to facilitate SPP’s strategic goal of continued development of a robust transmission system within the SPP footprint, while creating optimum value for stakeholders, members, and customers. This division has a total budget of $12.7 million for 2014 with 79 employees, including one incremental headcount in the 2014 budget.

The Engineering division is comprised of five departments:

- **Planning:** This department is primarily involved in transmission planning studies and the Integrated Transmission Planning (“ITP”) process. The Engineering Planning department has several key initiatives included in the 2014 Budget, such as process improvements in the Aggregate Transmission Service Studies (ATSS) and Generator Interconnection (GI) studies, FERC-mandated development and implementation of Long Term Congestion Rights subsequent to Integrated Marketplace go-live, and implementation of FERC Order 1000 for which the pre-qualification phase starts in May 2014. The department is planning to add one position in the 2014 budget for the congestion hedging function within Integrated Marketplace. A primary goal of the department is increasing the skill and knowledge level of its staff during 2014 through intensive training, developing its employees to a maturity and experience level to meet the goals for 2014 and SPP’s strategic plans. The various planning studies conducted by the Planning department produce revenues for SPP, which serve to reduce SPP’s Net Revenue Requirement. Revenue expected from studies is $3.0 million in 2014. This group has a staff of 40 employees.

- **Modeling:** This department will be involved with a wider range of industry groups in 2014-2016. The ability to perform certain dynamic stability studies is expected to be fully transitioned to SPP Engineering staff in 2014, eliminating third-party consulting services and resulting in cost savings. In relation to the Integrated Marketplace, new
processes will be executed associated with the Centralized Balancing Authority model efforts. The Modeling department is continuously gaining more experience with the Centralized Balancing Authority and ITP processes; therefore, no new headcount is planned for 2014. This department has a staff of 10 employees.

- **Interregional Coordination:** This department expects seams coordination activity to increase significantly over the next three-year period. The staff is working closely with SPP’s neighboring entities to ensure compliance with the interregional requirements of Order 1000. With the pending integration of Entergy into MISO, enhanced efforts with MISO and other neighbors on seams issues and joint operating agreements will become increasingly important. The department will also continue to support efforts to bring new members into SPP. This department has a staff of 9 employees.

- **R&D and Special Studies:** A main goal of this department is to assess new approaches and tools to refine performance objectives that align with future needs surrounding renewable resources, which are expected to drive the future of the power grid. To achieve this goal, the department is budgeting for extensive research and information tools, such as publications and membership to Electric Power Research Institute (“EPRI”), and for increased consulting services from industry experts to bring proven solutions into SPP to improve the planning process. SPP’s goal is to conduct centralized R&D activities that will benefit SPP’s stakeholders as a region. This department has a staff of 10 employees, including five in the Engineer in Rotation program.

- **Support and Resource Planning:** This new department provides business solutions and efficiencies, and resource coordination and allocation for engineering projects. The resource coordination and time tracking initiative, which began in 2012, has produced the ability to provide mitigation plans and track work efforts to produce long-term resource plans which can more accurately predict staffing needs. This department has a staff of 10 employees, including one incremental headcount in 2014 assigned to the Integrated Marketplace post-go-live Grandfather Agreement project.
Information Technology

The primary mission of IT is to develop, deploy, integrate and support applications and infrastructure for SPP's operational and corporate systems. IT has a total of 144 employees with a proposed 2014 budget of $41.5 million. This division has two main groups, IT Enterprise Operations and IT Applications. The IT Executive and Maintenance department has a budget of $16.1 million and includes compensation for a Chief Architect, Budget Analyst and IT Sourcing Manager, as well as equipment and software maintenance for company-wide IT systems ($15.2 million).

- IT Applications: This department provides 24x7 support for existing systems including transmission, market, and other support systems for SPP staff and members/customers. In addition, the department is responsible for coordinating software development efforts related to the Integrated Marketplace. This department plays an integral role in nearly all new projects, including creating requirements/test/rollback plans; developing software; providing technical leadership; defining, implementing and reviewing architecture; and providing ongoing maintenance and support for these systems. The IT Applications group also tests and implements all software upgrades. Primarily driven by system growth, a review of current staff levels and anticipated workload, indicated current IT Applications staffing is adequate for 2014, with contractor resources to handle extra workload driven by Integrated Marketplace. Although six incremental headcount were added in 2013, projected workload for 2014-2016 requires additional resources. It has not yet been determined
whether this workload will continue past 2015, so continued contractor assistance is included in the outside services portion of the budget ($1.3 million). The department is comprised of 93 employees with a budget of $14.5 million.

- IT Enterprise Operations: This department provides 24x7 support for all communications and networking systems, and all computer hardware and environmental needs for the SPP data center. Each of these activities is critical to SPP's transmission, market, and business processes. This department also provides technical direction, leadership, and architectural design for the communications, network, storage, backup/recovery, and computing platforms for all aspects of the IT infrastructure utilized within SPP. IT Enterprise Operations has maintained a consistent headcount level for the past two years, while accepting a significant increase in workload (number of servers, increases in storage, etc.). As a result of maintaining a highly qualified staff that is significantly leveraged across various technical platforms and disciplines and increasing automation processes, the department has been able to absorb the increased workload without adding staff. This department historically has not utilized contractor resources to fulfill its responsibilities, and does not anticipate doing so during 2014-2016. The department is comprised of 48 employees with a budget of $10.9 million.

**Compliance, Communications, and Market Monitoring**

This division has a staff of 30 employees with a budget of $4.2 million and is comprised of the following three departments. No additional headcount is anticipated for 2014-2016.

- Compliance: The main goals for this department in 2014 are enhancing member outreach services at the request of the Board Oversight Committee, and providing IT security and risk mitigation functions to the SPP organization, which includes cyber-vulnerability assessments, security monitoring, threat evaluation, and incident response. Improved processes, member outreach planning, and staff capabilities has
allowed existing staff to address current and future member evidence reviews and associated outreach needs. The department has a budget of $1.7 million with a staff of 13.

- Communications: The focus of this department is to build and execute a communication strategy which educates, creates trust, and protects the SPP brand. The department will continue to execute this strategy through various deliverables in 2014, especially involving communicating the value of transmission to stakeholders. The department has a budget of $0.5 million with a staff of 3.

- Market Monitoring: The main focus in 2014 for this department is to refine and implement analytical tools and monitoring screens, and continually develop staff to effectively monitor the Integrated Marketplace. This department is implementing automated systems and enhanced utilization of data to introduce further efficiencies and effectiveness to its monitoring mandate. Although increased workload is anticipated upon implementation of the Integrated Marketplace, management has determined the additional work can be absorbed without additional staff (which was initially considered for 2014 during the 2013 budget cycle). This is made possible through efficiency improvements associated with the new data warehouse and improvements in staff skills and expertise. The department has a budget of $2.0 million with a staff of 14.

**Process Integrity**

This division has a total staff of 47, with a proposed budget of $7.8 million for 2014.

- Project Management Office (PMO): This department is responsible for overseeing and coordinating the design, development, and implementation of projects within SPP. The department’s focus will be on Integrated Marketplace implementation during the first quarter of 2014, and the subsequent post-go-live projects thereafter. Project resource requirements in 2014 exceed internal resource availability; therefore, contractor resources will be utilized through the third quarter of 2014. As a result of process improvements and efficiency gains, one FTE will be available by the fourth quarter of
2014 to cover the resource need for the LEAN initiative in the Business Process Improvement department (see below). The department has a budget of $2.1 million with a staff of 13.

- Stakeholder Services: This group encompasses two departments, Customer Service and Customer Training. Customer Service will concentrate on customer interactions related to the Integrated Marketplace in 2014, as the volume of inquiries, requests, and outreach efforts is estimated to increase significantly. Four of the ten staff members will be dedicated to the Integrated Marketplace customer interactions. Customer Training will increase services and product delivery in response to demand for additional reliability-related training, new and/or updated operator tools, and Integrated Marketplace. The department has a budget of $3.3 million with a staff of 22.

- Internal Audit: The mission of this department is to provide independent and objective assurance and advisory services, which are designed to add value and improve SPP’s operations. The department will maintain and implement a risk-based audit schedule for SPP’s business and IT units and functions in 2014. One of the most important functions of this department is to coordination of the annual SSAE 16 audit, which evaluates SPP’s internal controls as a service organization. With the transition to the Integrated Marketplace in 2014, the focus will be on ensuring the effectiveness and reliability of SPP’s internal controls supporting Integrated Marketplace functions. The department has a budget of $1.2 million with a staff of 6.
• Business Process Improvements: This department originated with one FTE as a result of SPP’s organization-wide commitment to continuous improvement, and is projected to include a staff of four by 2014 (by re-allocating internal resources from various departments). The main focus of the department is to continue to implement the LEAN program throughout the SPP organization, to identify opportunities for process improvements, and to improve effectiveness and efficiencies. The department will also focus on SPP’s business continuity planning, which has become critical as a result of increased risks associated with the Integrated Marketplace. The budget currently includes a staff of two, with a budget of $0.4 million.

• Interregional Affairs: The department’s goal is increased involvement in the industry-wide standard development efforts by serving in leadership roles in both NERC and NAESB. The Reliability Standards staff provides SPP leadership in the national effort to develop meaningful and achievable reliability standards. Working with other SPP staff, members, and industry experts, the department works to ensure the reliability standards necessary to maintain a reliable bulk electric system for SPP are in place, with clear, effective, reasonable, and measurable requirements. The staff is comprised of four, with a budget of $0.8 million.

**Market Design and Development**

This department is responsible for the evolution of the energy and capacity markets, which is achieved through interactions and cooperation with members and other stakeholders while creating and enhancing markets in a member-driven way. Other goals of market design are to maintain reliability and pursue innovative ways to increase reliability through economics.

The department has three key responsibilities:

• Create and modify the SPP regional market design through a member-driven process
• Conduct quality assurance functions to ensure implemented processes and systems are consistent with the market design
• Support other market-related initiatives
The backlog of Integrated Marketplace enhancements demonstrates the continued evolution of markets and the need to facilitate and manage the growth. This department also assists in the development of SPP membership. In addition, this department manages coordination and communications with other RTOs regarding market development.

The Market Design department has a 2014 budget of $1.0 million and a total staff of six employees.

**Legal and Regulatory Policy**

The division for Legal and Regulatory Policy is comprised of a staff of 26 FTEs with a total budget of $6.6 million for 2014.

- **Legal:** The Legal department continues to evolve into a value-added internal resource with the goal of significantly reducing costs for and dependency on outside counsel, especially in FERC matters. Over the past three years, the outside legal services budget has decreased; however, Integrated Marketplace filings continue to require third party services. Integrated Marketplace filings and disputes are anticipated to increase significantly in 2014. The department has a staff of 12 and a budget of $4.1 million.

- **Regulatory Policy:** In 2014, this department is expected to have increased responsibility regarding regulatory filings related to the Integrated Marketplace protocols and tariff implementation, including filings necessary to implement the Readiness and Reversion Plans. As a result of improved staff expertise and knowledge of the Integrated Marketplace, a reduced reliance on outside consultants is anticipated, and no consulting dollars are budgeted for 2014. The department has a staff of 14 and a budget of $2.5 million.
Finance

The Finance division is comprised of the Settlements, Credit and Risk Management, and Accounting and Purchasing departments. This division has a 2014 budget of $4.8 million with a total staff of 39 FTEs.

- **Settlements:** This department is comprised of two primary areas to support market and transmission settlements. In 2014, the department’s focus will be on ensuring a successful go-live and providing post-implementation support of the Integrated Marketplace. Recent software upgrades, process improvements, efficiency metrics tracking, and the cross training of staff will continue to result in cost savings by avoiding the need for temporary consulting support. The total departmental headcount was reduced by one, as the result of reallocating duties when a Settlement Analyst position was vacated (transferred to another position within SPP). The department has a budget of $2.9 million with a staff of 25.

- **Credit and Risk Management:** This department administers the extension of credit to market participants and works to protect the market participants and members from losses through diligent underwriting and collection efforts. The products within the Marketplace are much more complex and represent a significant increase in default risk to all Marketplace participants. As a result, the department’s goal in 2014 and beyond will be to carefully monitor the increased risk and
respond as necessary to continually protect the market participants and members. The department has a budget of $0.6 million with a staff of 4.

- Accounting and Purchasing: This department is responsible for invoicing, cash management, payment processing, internal and external reporting, budgeting and forecasting, corporate accounting, and end-to-end procurement services. This department has a staff of 10 employees. Although one position was proposed to be added for 2014 in the 2013 budget presentation, no additional headcount is foreseen in the 2014 budget due to efficiencies achieved in financial reporting with software automation and increased level of experience in key positions. The department has a budget of $1.3 million with a staff of 10.

**Corporate Services**

This division is comprised of Human Resources, Corporate Facilities, and Corporate Administrative Services departments. The 2014 budget for Corporate Services represents a 33% reduction compared to the 2013 budget. After occupying the new corporate campus for one year, office expense savings have been recognized due to campus consolidation. Additional savings in utility expenses resulted from SPP’s new energy efficient facilities. The elimination leasing of additional office space and associated decommissioning costs result in a $0.3 million reduction in the budget over 2013. Meeting expenses have also been reduced due to elimination of certain working group meetings, and the ability to host meetings at the SPP campus for approximately one-third of the cost of hosting a meeting at a hotel. Certain employee services included in the 2013 budget were re-evaluated, and alternative solutions were devised for a fraction of the original cost. As an example the company is implementing a wellness kiosk at a fraction of the cost of the previously planned on-site wellness clinic.

The Human Resources department has implemented software upgrades which result in savings in fees paid to third party providers, and resulted in improved HR interface capabilities with SPP employees. Expense reductions are expected in pre-employment screenings and new employee activities in general. This is the result of significantly fewer new hires than in prior
years. The Corporate Services division has a total staff of 29 FTEs and a 2014 budget of $6.4 million.

**Officer and Administrative**

This group of nine officers is comprised of SPP’s CEO and President, COO, and seven executives overseeing the overall business operations and providing strategic direction to SPP as a whole. Overall vacancy is reflected in the Administrative department ($1.1 million in 2014). Also included are certain corporate administrative costs such as corporate insurance expenses, pension plan and retiree healthcare funding, and property taxes.

The total budget for 2014 for this division is $11.3 million, with a staff of ten.
VI. Capital Projects

Beginning in January, a comprehensive list of new and on-going projects was compiled for consideration for the 2014 – 2016 Budget under the direction of the Project Review and Prioritization Committee (PRPC) and in collaboration with staff from the Project Management Office (PMO), Accounting and IT departments. The PRPC worked closely with Project Managers, IT Directors and vendor managers to scope and estimate anticipated workload associated with the implementation of the projects. Considering the Integrated Marketplace remains the highest priority and consumes significant resource capacity, new projects were carefully reviewed to ensure no projects were added that would impede the go-live date of the program. Consulting dollars were incorporated into the budget to supplement for expertise and/or staffing constraints as deemed necessary.

### 2014 - 2016 Capital Expenditures by Year ($ millions)

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Integrated Marketplace Go-Live</td>
<td>5.8</td>
<td>-</td>
<td>-</td>
<td>5.8</td>
</tr>
<tr>
<td>Integrated Marketplace Post-Go-Live</td>
<td>17.5</td>
<td>2.5</td>
<td>-</td>
<td>20.0</td>
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<tr>
<td>Carry Over Projects</td>
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<td>9.4</td>
<td>0.2</td>
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</tr>
<tr>
<td>New Projects</td>
<td>0.6</td>
<td>0.2</td>
<td>-</td>
<td>0.7</td>
</tr>
<tr>
<td>Total Non-Foundation Projects</td>
<td>26.0</td>
<td>12.1</td>
<td>0.2</td>
<td>38.3</td>
</tr>
<tr>
<td>Foundation</td>
<td>11.1</td>
<td>7.0</td>
<td>5.4</td>
<td>23.5</td>
</tr>
<tr>
<td><strong>Total Capital Budget</strong></td>
<td><strong>37.1</strong></td>
<td><strong>19.2</strong></td>
<td><strong>5.6</strong></td>
<td><strong>61.8</strong></td>
</tr>
</tbody>
</table>

The three-year budget identifies $61.8 million in total capital expenditures with $38.3 million tied to specific projects and initiatives and $23.5 million in foundation related maintenance capital expenditures. SPP expects 2014 capital expenditure spending will exceed $37 million. Ten projects are classified as “Integrated Marketplace Post Go-Live”, which are supplementary projects either mandated by regulators or requested by SPP members, and comprise $20.0 million of the three-year total. Also included are 11 carry-over projects ($11.8 million) and 5 new projects ($0.7 million), with $5.8 million remaining on the Integrated Marketplace Go-Live project.

The chart below illustrates the aggregate annual administrative fee impact of the projects.
The following section describes the Integrated Marketplace and other noteworthy projects in greater detail. A complete list of initiatives and associated capital and operating budgets appear in the Supplementary Schedules section.

Integrated Marketplace

The 2014 budget includes the final phases of work associated with the Integrated Marketplace. Following the launch of the Integrated Marketplace, SPP will have implemented the following large-scale initiatives:

- Day-Ahead Market
- Transmission Congestion Rights
- Reliability Unit Commitment
- Real-Time Balancing Market
- Operating Reserve Market
- Consolidated Balancing Authority
The primary business drivers of the Integrated Marketplace program include the following: 1) to further recognize benefits of the diversity of generating unit resource assets, 2) optimize utilization of the transmission system within SPP, and 3) minimize overall costs to consumers.

The Integrated Marketplace allows for a single, larger consolidated balancing authority, which produces more efficient balancing and dispatch of generation and load. The primary business benefits of the Integrated Marketplace program as determined from the Cost Benefit Task Force cost/benefit analysis are: 1) $45.0 million - $100.0 million per year net benefit to the SPP region based on various gas cost assumptions, and 2) a more efficient utilization of generation assets through centralized unit commitment. The program will be considered complete when:

- SPP assumes the role of balancing authority from members, and
- SPP implements and completes a monthly settlement for each of the following markets-related initiatives:
  - Day Ahead Markets
  - Real Time Balancing Market
  - Operating Reserves
  - Transmission Congestion Rights Markets

SPP’s Board of Directors approved a capital budget of $105.6 million during its April 2011 meeting. In April 2013, the Board approved additional funding of $9.4 million for the primary purpose of funding additional resources (consultants, hardware, and software) needed to meet the March 1, 2014 go-live date, bringing the total project budget to $115.0 million. The project total shown below represents the current 2013 forecast, which is $0.2 over the revised budget.

<table>
<thead>
<tr>
<th>Integrated Marketplace Capital Expenditures by Year ($ millions) *</th>
<th>2007-2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marketplace</td>
<td>8.6</td>
<td>20.9</td>
<td>41.6</td>
<td>35.8</td>
<td>5.8</td>
<td>112.6</td>
</tr>
<tr>
<td>CBA</td>
<td>0.2</td>
<td>1.1</td>
<td>0.6</td>
<td>0.7</td>
<td>-</td>
<td>2.6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>8.7</strong></td>
<td><strong>22.0</strong></td>
<td><strong>42.2</strong></td>
<td><strong>36.4</strong></td>
<td><strong>5.8</strong></td>
<td><strong>115.2</strong></td>
</tr>
</tbody>
</table>

* excludes capitalized interest.

**Integrated Marketplace Post-Go-Live Projects**

The post-go-live projects represent post-implementation enhancements to the Integrated Marketplace. Preliminary planning work is underway in 2013 for five of these projects. The total projected capital expense for 2014 – 2016 is $20.0 million, with a project total of $21.7 million including prior year costs. All post-go-live projects are expected to be completed and in service before the end of 2015.
The budget estimates for the Post Go-Live Projects were refined during the 2014 budget cycle. This analysis resulted in significant increases over the 2013 total project estimates. The major driver of the Market-to-Market estimate increase ($5.2 million) is due to refinement of the design and the use of consultants to implement this functionality. The major driver of the increase in the Long-Term Congestion Rights ($2.7 million) and Enhanced Combined Cycle ($1.5 million) projections was the inclusion of contingencies in the estimates. Contingencies were added due to unresolved issues surrounding impacts to other Engineering planning processes, and to cover potential cost overruns since the vendor has never before developed this functionality. A decrease was reflected in the Regulation Compensation budget ($0.8 million) due to refinement of the design which resulted in a simpler implementation than originally contemplated.

**Combined Cycle Enhancements**

These enhancements will allow market participants to submit resource offers for each configuration of a combined cycle unit. Each configuration will be modeled in the market-clearing engine as a separate resource in order to select the most economic configuration for unit commitment and dispatch. The MOPC is expected to authorize this project during its October 2013 meeting. Once authorized, work will commence, and completion is anticipated in second quarter of 2015.

**Regulation Compensation (FERC Order 755)**

FERC Order 755 requires RTOs to provide a two-part payment to resources providing regulation service in the Integrated Marketplace. Tariff changes, protocol changes, and software changes will be required to comply with this Order. Work on this project is expected to commence in third quarter of 2013, and completion is anticipated in second quarter of 2015.

**Long-Term Transmission Congestion Rights (LTTCRs)**

FERC Order 681 requires Load Serving Entities (LSEs) to have priority in the allocation of long-term firm transmission rights. FERC expects most transmission organizations to be able to use their current allocation/auction systems to allow LSEs to nominate source-to-sink transmission rights on a longer-term basis than what is currently available. This project will consist of enhancements to the Nexant software and will establish a process providing LSEs the ability to nominate LTTCRs for more than one year. Work is expected to commence in third quarter of 2013, and completion is anticipated in 2015.

**Market-to-Market**

Market-to-market coordination logic is required as an addition to the Integrated Marketplace system software to manage congestion appropriately and efficiently.
between SPP and neighboring markets. This project adds functionality to the market clearing engine enabling market-to-market coordination. This provides the ability for each market to request re-dispatch of generation to solve a constraint at a lower cost, therefore reducing the overall cost of congestion. Work is expected to commence in third quarter of 2013, and completion is anticipated in the first quarter of 2015.

**AFC Granularity Changes for TSRs**

The objective of this project is to change how the available flow-gate capability (AFC) associated with transmission service requests (TSR) is evaluated to accommodate the SPP Balancing Authority (BA). Once SPP is the BA, this change provides SPP and its members a more accurate evaluation of transmission service impacts. Changes are expected for many applications within Operations, IT, Transmission Planning and Settlements departments. Work is expected to commence in first quarter of 2015, and completion is anticipated in late 2015.

**Post Go-Live Capital Expenditures by Year ($ millions)**

<table>
<thead>
<tr>
<th>Post-Go-Live Projects</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market-to-Market</td>
<td>0.7</td>
<td>5.9</td>
<td>0.5</td>
<td>-</td>
<td>7.0</td>
</tr>
<tr>
<td>Combined Cycle Enhancements</td>
<td>0.2</td>
<td>4.3</td>
<td>0.1</td>
<td>-</td>
<td>4.6</td>
</tr>
<tr>
<td>Long-Term TCRs (LTTCRs)</td>
<td>0.2</td>
<td>4.0</td>
<td>0.1</td>
<td>-</td>
<td>4.3</td>
</tr>
<tr>
<td>Regulation Compensation (FERC Order 755)</td>
<td>0.5</td>
<td>2.4</td>
<td>0.3</td>
<td>-</td>
<td>3.2</td>
</tr>
<tr>
<td>AFC Granularity Changes for TSRs</td>
<td>-</td>
<td>-</td>
<td>1.4</td>
<td>-</td>
<td>1.4</td>
</tr>
<tr>
<td>IT Environments Buildout for IM</td>
<td>-</td>
<td>0.6</td>
<td>-</td>
<td>-</td>
<td>0.6</td>
</tr>
<tr>
<td>Grandfather Agreement Carve Out (GFA)</td>
<td>-</td>
<td>0.3</td>
<td>-</td>
<td>-</td>
<td>0.3</td>
</tr>
<tr>
<td>Assets Pseudo-Tying Out of SPP BA</td>
<td>0.2</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.2</td>
</tr>
<tr>
<td>Sunset Clause for Load Submittal for Legacy BAs</td>
<td>-</td>
<td>-</td>
<td>0.2</td>
<td>-</td>
<td>0.2</td>
</tr>
<tr>
<td>Marketplace Data for MPs Post Go-Live</td>
<td>-</td>
<td>-</td>
<td>0.1</td>
<td>-</td>
<td>0.1</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1.7</strong></td>
<td><strong>17.5</strong></td>
<td><strong>2.5</strong></td>
<td>-</td>
<td><strong>21.7</strong></td>
</tr>
</tbody>
</table>

**Other Foundation Projects**

**IT Systems Administration Foundation**

IT Systems Administration foundation projects include the replacement of systems no longer covered under existing warranties. Also included are new virtualized servers, which will be housed within an ESX Host Cluster. As required, associated ESX Host(s) purchases are also included in the project costs. While virtualization to consolidate hardware is the main focus surrounding server replacement, some physical servers are still required to replace certain systems currently not candidates for virtualization. Implementation of the Integrated
Marketplace drives the need for additional data storage, information security, back-up, recovery and archiving solutions. The IT Systems Foundation budget includes hardware and software to meet these needs. The total project cost is estimated at $8.2 million from 2014 through 2016.

**IT Network Telecom Foundation**

Items in the Telecom/Network/Security (TNS) Foundation budget are requested for various reasons, the most prominent being improvements to existing network architecture to achieve the highest level of system availability, which is required by a Centralized Balancing Authority and the Integrated Marketplace. Equipment planned for replacement has either been in service for over three years, has an increased risk of failure, and/or lacks feature sets conducive to achieving the availability required by the Integrated Marketplace and other high availability projects. Upgrades of licensing and module/components, which will extend the life of assets already in production lacking port density or capacity, are also included.

Additional costs include hardware to isolate the Chenal and Maumelle ESP environments into separate core infrastructures. At present, certain core infrastructure is leveraged across multiple environments, which allows for issues outside of the ESP to impact systems within the ESP. This project allows for a “best practice” design for critical infrastructure.

Additional Network/Security lab equipment provides the Telecom/Network/Security team an isolated test environment for software upgrades/hardware replacements, new features/protocols, and stress/capacity. The environment infrastructure will be identical to SPP’s production, QA and test environments. The investment in this lab will produce a positive impact on the performance and reliability of SPP’s network and security infrastructure and will allow for the availability metrics required by the business.

Total project cost is estimated at $7.6 million from 2014 through 2016.

**Foundation – IT Applications**

The complexity of the Integrated Marketplace requires more stringent processes surrounding software deployment and release management, and reconciliation of the availability and capability of development tools. Internally customized processes and tools have proven unreliable for long-term deployments, thus creating a necessity for implementation of industry accepted standards, methods, and models. The components identified under this initiative focus on improved support, data modeling, and patch management for the key database management system. Subject-matter expert consultants are utilized for increasing levels of support for application and data warehouse solutions. Enhanced problem isolation through centralized logging increases SPP’s capability to identify root causes of issues, thus contributing to the Integrated Marketplace high availability requirements. Improved patching for databases
improves SPP’s capability to meet CIP standards. Outside consultants will train and assist SPP personnel on two complex and critical systems. Each of these items promotes efficiencies within IT Applications. Total project costs are estimated at $3.9 million from 2014 through 2016.

### Foundation / Other Capital Expenditures by Year ($ millions) (1)

<table>
<thead>
<tr>
<th>Foundation / Other</th>
<th>Prior Yr(s)</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upgrades / System Replacements</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DTS to TTSE (2)</td>
<td>-</td>
<td>-</td>
<td>4.4</td>
<td>-</td>
<td>4.4</td>
</tr>
<tr>
<td>Transmission Settlements ETSE &amp; Alstom ETS</td>
<td>-</td>
<td>0.1</td>
<td>3.9</td>
<td>0.1</td>
<td>4.0</td>
</tr>
<tr>
<td>Netezza</td>
<td>2.7</td>
<td>0.2</td>
<td>0.1</td>
<td>-</td>
<td>3.0</td>
</tr>
<tr>
<td>EMS Upgrade / Readiness</td>
<td>0.7</td>
<td>1.3</td>
<td>0.4</td>
<td>-</td>
<td>2.4</td>
</tr>
<tr>
<td>Data Center Migration</td>
<td>0.6</td>
<td>0.1</td>
<td>-</td>
<td>-</td>
<td>0.7</td>
</tr>
<tr>
<td>Project Server</td>
<td>-</td>
<td>0.3</td>
<td>-</td>
<td>-</td>
<td>0.3</td>
</tr>
<tr>
<td>Foundation</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IT Systems Foundation</td>
<td>-</td>
<td>3.1</td>
<td>2.8</td>
<td>2.3</td>
<td>8.2</td>
</tr>
<tr>
<td>IT Network Telecom</td>
<td>-</td>
<td>5.0</td>
<td>1.3</td>
<td>1.3</td>
<td>7.6</td>
</tr>
<tr>
<td>IT Applications Foundation</td>
<td>-</td>
<td>1.5</td>
<td>1.6</td>
<td>0.8</td>
<td>3.9</td>
</tr>
<tr>
<td>Operations Foundation</td>
<td>-</td>
<td>0.7</td>
<td>0.5</td>
<td>0.4</td>
<td>1.1</td>
</tr>
<tr>
<td>Other / Carryover</td>
<td>-</td>
<td>1.5</td>
<td>1.6</td>
<td>0.8</td>
<td>3.9</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>4.0</strong></td>
<td><strong>13.8</strong></td>
<td><strong>16.6</strong></td>
<td><strong>5.6</strong></td>
<td><strong>39.5</strong></td>
</tr>
</tbody>
</table>

(1) Excludes Integrated Marketplace and Post Go-Live Projects

(2) Upgrade Dispatcher Training Simulator (DTS) to Training and Testing Simulated Environment (TTSE)
VII. Debt Service

SPP secures funds from financial institutions and investors to finance its capital projects. Costs of the capital projects are paid directly from the funds provided by the borrowings. These costs are not directly included in SPP’s Net Revenue Requirement; however, annual principal and interest payments for borrowings (net of capitalized interest) considered in the Net Revenue Requirement calculation. SPP’s outstanding borrowings are projected to equal $258.3 million as of January 1, 2014. Interest and principal payments included in the 2014 Net Revenue Requirement are shown in the table below.

<table>
<thead>
<tr>
<th>2014 Debt Service ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Issue Date</td>
</tr>
<tr>
<td>------------</td>
</tr>
<tr>
<td>5.31% notes due 2014</td>
</tr>
<tr>
<td>5.45% notes due 2016</td>
</tr>
<tr>
<td>5.51% notes due 2027</td>
</tr>
<tr>
<td>4.82% construction notes due 2042</td>
</tr>
<tr>
<td>3.55% integrated markets notes due 2024</td>
</tr>
<tr>
<td>3.00% capital funding notes due 2024</td>
</tr>
<tr>
<td>3.25% capital funding notes due 2024</td>
</tr>
<tr>
<td>New funding</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>

SPP anticipates issuing $70.0 million in new borrowings during the first quarter of 2014 to fund capital projects for 2014-2016. Due to the favorable interest rate environment and SPP’s credit rating of “A” for senior unsecured debt and “A+” for senior secured debt, the budget assumed the cost of new borrowing to be 4.0% with a term of ten years.

SPP capitalizes a portion of interest expense in association with Integrated Marketplace development costs, and expects to do the same for the Marketplace post-go-live projects that meet SPP’s capitalization threshold criteria. According to U.S. GAAP, the historical cost of acquiring an asset should include all costs incurred to bring it to the condition and location necessary for its intended use. Financing costs incurred for an asset during the construction or development period are considered part of the asset's historical acquisition cost. In accordance
with GAAP, SPP’s policy is to capitalize interest costs for assets meeting certain criteria to obtain a measure of acquisition cost that more closely reflects SPP’s total investment in the asset. In summary, projects with anticipated costs exceeding $5.0 million with an anticipated duration of greater than 18 months would be subject to interest capitalization.

### Impact of Capitalized Interest ($ millions)

<table>
<thead>
<tr>
<th>Note Details</th>
<th>Actual Interest Payments</th>
<th>Impact on Admin Fee</th>
<th>Capitalized Interest*</th>
<th>Net Revenue Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2014 Budget</td>
<td>Impact on Admin Fee</td>
<td>Capitalized Interest*</td>
<td>2014 Budget</td>
</tr>
<tr>
<td>5.31% notes due 2014</td>
<td>$0.2</td>
<td>$ 0.001</td>
<td></td>
<td>$0.2</td>
</tr>
<tr>
<td>5.45% notes due 2016</td>
<td>$0.7</td>
<td>$ 0.002</td>
<td></td>
<td>$0.7</td>
</tr>
<tr>
<td>5.51% notes due 2027</td>
<td>$0.2</td>
<td>$ 0.001</td>
<td></td>
<td>$0.2</td>
</tr>
<tr>
<td>4.82% construction notes</td>
<td>$3.1</td>
<td>$ 0.009</td>
<td></td>
<td>$3.1</td>
</tr>
<tr>
<td>due 2042</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3.55% integrated markets</td>
<td>$2.4</td>
<td>$ 0.007</td>
<td>($0.5)</td>
<td>$2.0</td>
</tr>
<tr>
<td>notes due 2023</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3.00% capital funding</td>
<td>$1.5</td>
<td>$ 0.004</td>
<td>($0.3)</td>
<td>$1.1</td>
</tr>
<tr>
<td>notes due 2024</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3.25% capital funding</td>
<td>$1.6</td>
<td>$ 0.005</td>
<td>($0.3)</td>
<td>$1.3</td>
</tr>
<tr>
<td>notes due 2024</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New funding</td>
<td>$2.6</td>
<td>$ 0.007</td>
<td>($0.1)</td>
<td>$2.5</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$12.2</strong></td>
<td><strong>$0.0350</strong></td>
<td><strong>($1.2)</strong></td>
<td><strong>$11.0</strong></td>
</tr>
</tbody>
</table>

*Capitalization of interest on long-term debt associated with the development of the Integrated Marketplace and applicable post-go-live projects results in a reduction to the admin fee of $0.0317. This assumes the capitalized interest is not deemed to be impaired.*
VIII. Supplemental Analysis and Schedules

Financial Statement Forecasts

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### Income Statement 2013-2014 Comparison ($ millions)

<table>
<thead>
<tr>
<th></th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
<th>2014 Prior*</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Income</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tariff Administration Service</td>
<td>$113.8</td>
<td>$112.8</td>
<td>$132.6</td>
<td>$137.5</td>
</tr>
<tr>
<td>Fees &amp; Assessments</td>
<td>28.2</td>
<td>24.9</td>
<td>26.8</td>
<td>29.1</td>
</tr>
<tr>
<td>Contract Services Revenue</td>
<td>0.7</td>
<td>0.4</td>
<td>0.5</td>
<td>0.7</td>
</tr>
<tr>
<td>Miscellaneous Income</td>
<td>4.3</td>
<td>4.6</td>
<td>3.4</td>
<td>4.1</td>
</tr>
<tr>
<td><strong>Total Income</strong></td>
<td>$147.0</td>
<td>$142.7</td>
<td>$163.2</td>
<td>$171.5</td>
</tr>
<tr>
<td><strong>Expense</strong></td>
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<td></td>
</tr>
<tr>
<td>Salary</td>
<td>52.4</td>
<td>53.0</td>
<td>55.3</td>
<td>54.5</td>
</tr>
<tr>
<td>Benefits &amp; Taxes</td>
<td>24.1</td>
<td>24.0</td>
<td>26.0</td>
<td>25.5</td>
</tr>
<tr>
<td>Continuing Education</td>
<td>0.9</td>
<td>0.7</td>
<td>1.0</td>
<td>0.8</td>
</tr>
<tr>
<td>Salary &amp; Benefits</td>
<td>$77.4</td>
<td>$77.7</td>
<td>$82.2</td>
<td>$80.8</td>
</tr>
<tr>
<td>Employee Travel</td>
<td>2.6</td>
<td>2.1</td>
<td>2.2</td>
<td>2.4</td>
</tr>
<tr>
<td>Administrative</td>
<td>5.0</td>
<td>4.0</td>
<td>4.7</td>
<td>5.5</td>
</tr>
<tr>
<td>Assessments &amp; Fees</td>
<td>16.3</td>
<td>14.7</td>
<td>15.3</td>
<td>17.2</td>
</tr>
<tr>
<td>Meetings</td>
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<td>0.9</td>
<td>1.5</td>
</tr>
<tr>
<td>Communications</td>
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<td>3.9</td>
<td>3.9</td>
<td>4.5</td>
</tr>
<tr>
<td>Leases</td>
<td>0.4</td>
<td>0.4</td>
<td>0.2</td>
<td>0.1</td>
</tr>
<tr>
<td>Maintenance</td>
<td>10.5</td>
<td>11.0</td>
<td>15.9</td>
<td>15.3</td>
</tr>
<tr>
<td>Services</td>
<td>16.0</td>
<td>15.3</td>
<td>14.3</td>
<td>15.7</td>
</tr>
<tr>
<td>Regional State Committee</td>
<td>0.3</td>
<td>0.3</td>
<td>0.3</td>
<td>0.4</td>
</tr>
<tr>
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<td>598</td>
<td>618</td>
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* 2014 projection as presented in the 2013 budget
### Income Statement 2014-2016
($ millions)

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<th>2016 Budget</th>
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<td>5.1</td>
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<td>348.2</td>
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<td>$0.426</td>
<td>$0.417</td>
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<td>$0.350</td>
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<td>603</td>
<td>605</td>
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Balance Sheet  
($ millions)

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<th>12/31/2014</th>
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<tr>
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<td><strong>$310.1</strong></td>
</tr>
</tbody>
</table>

|                  |            |            |
| **LIABILITIES & EQUITY** |            |            |
| Liabilities       |            |            |
| Current Liabilities |            |            |
| Accounts Payable (net) | $9.3      | $3.3      |
| Customer Deposits | 42.4       | 45.4      |
| Current Maturities of LT Debt | 23.0     | 24.4      |
| Other Current Liabilities | 26.6     | 25.3      |
| Deferred Revenue | 5.5        | 4.5       |
| Total Current Liabilities | 106.8     | 103.0     |
| Long Term Liabilities |            |            |
| US Bank 5.45% Senior Notes - 2016 | 9.0 | 3.0 |
| US Bank Maumelle Mortgage - 2027 | 3.5 | 3.3 |
| Campus 4.82% Senior Notes - 2042 | 63.0 | 61.9 |
| Integrated Marketplace 3.55% Senior Notes - 2024 | 64.8 | 57.8 |
| Capital Funding 3.00% - 2024 | 46.3 | 41.3 |
| Capital Funding 3.25% - 2024 | 48.8 | 43.8 |
| Additional Financing | 0.0        | 70.0      |
| Other Long Term Liabilities | 9.1       | 8.9       |
| Total Long Term Liabilities | 244.4     | 289.9     |
| Net Income        | (14.7)     | (37.5)    |
| Members' Equity   | (30.7)     | (45.4)    |
| Total Members' Equity | (45.4)    | (82.9)    |
| **TOTAL LIABILITIES & EQUITY** | **$305.8** | **$310.1** |
## Cash Flow Forecast 2014-2016 ($ millions)

### OPERATING CASH

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Beginning Cash on Hand</strong></td>
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<td>$4.6</td>
<td>$2.1</td>
</tr>
<tr>
<td><strong>Income</strong></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Tariff Administration Service</td>
<td>$132.4</td>
<td>$145.6</td>
<td>$144.7</td>
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<td>0.5</td>
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<td><strong>Operating Income</strong></td>
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<td><strong>162.2</strong></td>
<td><strong>161.7</strong></td>
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<td><strong>Expense</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Salary &amp; Benefits</td>
<td>81.4</td>
<td>84.9</td>
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<tr>
<td>Employee Travel</td>
<td>2.2</td>
<td>2.1</td>
<td>2.2</td>
</tr>
<tr>
<td>Administrative</td>
<td>4.7</td>
<td>5.0</td>
<td>5.1</td>
</tr>
<tr>
<td>Meetings</td>
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<td>0.9</td>
<td>0.9</td>
</tr>
<tr>
<td>Communications</td>
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<td>4.2</td>
</tr>
<tr>
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<tr>
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<td>Services</td>
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<td>0.3</td>
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<td>11.0</td>
<td>13.8</td>
<td>10.9</td>
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<tr>
<td>Debt Repayments*</td>
<td>13.0</td>
<td>24.0</td>
<td>21.4</td>
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<tr>
<td><strong>Operating Expense</strong></td>
<td><strong>147.8</strong></td>
<td><strong>164.7</strong></td>
<td><strong>162.3</strong></td>
</tr>
<tr>
<td><strong>Ending Cash on Hand</strong></td>
<td>$4.6</td>
<td>$2.1</td>
<td>$1.4</td>
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<tr>
<td><strong>Recommended Admin Fee / MWh</strong></td>
<td>$0.381</td>
<td>$0.426</td>
<td>$0.417</td>
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### CAPITAL CASH

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<th>2015</th>
<th>2016</th>
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<td><strong>$35.5</strong></td>
<td><strong>$13.9</strong></td>
<td><strong>$7.7</strong></td>
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</table>

* $10 million of the total $23 million of debt repayments in 2014 will be financed from proceeds of new financing, therefore the net cash outflow for debt repayments from operating cash is shown as $13 million.*
### Capital Projects List ($ millions)

#### 2014 - 2016 Capital Project Budget (Including Carry Over Costs)

<table>
<thead>
<tr>
<th>Project</th>
<th>Original Go-Live</th>
<th>Post Go-Live</th>
<th>Carry Over Projects</th>
<th>2014 New Projects</th>
<th>IT / Ops Foundation</th>
<th>Total Project Capital Budget</th>
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</thead>
<tbody>
<tr>
<td>Project</td>
<td>Prior Year(s)</td>
<td>2013 Fcst</td>
<td>2014 Bud</td>
<td>2015 Fcst</td>
<td>2016 Fcst</td>
<td>2014 - 2016 Total (excludes prior years)</td>
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<td>QA ICCP Buildout</td>
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<td>IT / Ops Foundation</td>
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<td>IT Applications Foundation</td>
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<td>Total 2014 - 2016 Total (excludes prior years)</td>
<td>$73.8</td>
<td>$41.4</td>
<td>$37.1</td>
<td>$19.2</td>
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<td>Total Project Capital Budget</td>
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## Outside Services by Function
($ millions)

<table>
<thead>
<tr>
<th>DESCRIPTION OF SERVICES</th>
<th>2014</th>
<th>2013</th>
<th>Inc / (Dec)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Integrated Marketplace</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SSAE 16 Audits</td>
<td>$0.4</td>
<td>$0.6</td>
<td>($0.2)</td>
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<tr>
<td>Staff augmentation, Training</td>
<td>0.4</td>
<td>0.5</td>
<td>(0.2)</td>
</tr>
<tr>
<td>Staff augmentation, Market Design</td>
<td>0.0</td>
<td>0.3</td>
<td>(0.3)</td>
</tr>
<tr>
<td>Staff augmentation, Market Monitoring</td>
<td>0.1</td>
<td>0.3</td>
<td>(0.2)</td>
</tr>
<tr>
<td>Staff augmentation, Operations</td>
<td>0.3</td>
<td>0.6</td>
<td>(0.2)</td>
</tr>
<tr>
<td><strong>Total Integrated Marketplace</strong></td>
<td>1.3</td>
<td>2.2</td>
<td>(1.0)</td>
</tr>
<tr>
<td><strong>Staff Augmentation</strong></td>
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<td></td>
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<tr>
<td>IT</td>
<td>1.6</td>
<td>1.6</td>
<td>(0.0)</td>
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<tr>
<td>PMO / BPI</td>
<td>0.3</td>
<td>0.0</td>
<td>0.3</td>
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<tr>
<td>Regulatory</td>
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<td>(0.5)</td>
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<tr>
<td>Legal</td>
<td>2.5</td>
<td>3.2</td>
<td>(0.7)</td>
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<td>Engineering Modeling</td>
<td>0.2</td>
<td>0.3</td>
<td>(0.1)</td>
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<td><strong>Total Staff Augmentation</strong></td>
<td>4.6</td>
<td>5.6</td>
<td>(1.0)</td>
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<tr>
<td><strong>Information Technology</strong></td>
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<tr>
<td>OATI Monthly service fee</td>
<td>1.5</td>
<td>1.4</td>
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<td>After hours monitoring of IT Command Center</td>
<td>0.3</td>
<td>0.3</td>
<td>(0.0)</td>
</tr>
<tr>
<td>Operations Wind Forecasting Analysis</td>
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<td>0.3</td>
<td>0.1</td>
</tr>
<tr>
<td>Misc. IT services (cabling, storage, asset disposal)</td>
<td>0.1</td>
<td>0.1</td>
<td>(0.1)</td>
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<tr>
<td><strong>Total Information Technology</strong></td>
<td>2.3</td>
<td>2.1</td>
<td>0.2</td>
</tr>
<tr>
<td><strong>Other</strong></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Board of Directors Fees, audits, etc.</td>
<td>1.0</td>
<td>1.0</td>
<td>(0.0)</td>
</tr>
<tr>
<td>Communications and training</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
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<tr>
<td>Corporate services</td>
<td>0.9</td>
<td>1.2</td>
<td>(0.3)</td>
</tr>
<tr>
<td>Engineering studies / other</td>
<td>1.8</td>
<td>1.5</td>
<td>0.3</td>
</tr>
<tr>
<td>Regional Entity hearings and audits</td>
<td>1.5</td>
<td>1.5</td>
<td>(0.0)</td>
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<tr>
<td>FERC Order 1000</td>
<td>0.4</td>
<td>0.4</td>
<td>(0.1)</td>
</tr>
<tr>
<td>Ops IDC / Other</td>
<td>0.5</td>
<td>0.3</td>
<td>0.3</td>
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<tr>
<td>Regional State Committee</td>
<td>0.3</td>
<td>0.3</td>
<td>0.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$14.6</td>
<td>$16.3</td>
<td>($1.4)</td>
</tr>
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</table>
### Analysis of 2013 Fees & Assessments ($ millions)

<table>
<thead>
<tr>
<th>Fees &amp; Assessments, Revenue and Expense</th>
<th>2013 Forecast</th>
<th>2013 Budget</th>
<th>Variance Fav/(Unfav)</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPP Regional Entity Revenue</td>
<td>$10.2</td>
<td>$11.5</td>
<td>$(1.3)</td>
<td>Revenue for SPP RE is recognized as earned based on expense totals. In 2013, the RE expects to be favorable in comparison to their total expense budget, resulting in lower corresponding revenues.</td>
</tr>
<tr>
<td>FERC Fee Assessments (Sch.12)</td>
<td>$14.7</td>
<td>$16.7</td>
<td>(2.0)</td>
<td>FERC Fee Assessment revenue is recognized as collected. The Schedule 12 rate decreased in 2013 but the decrease was not reflected in the 2013 budget due to timing issues.</td>
</tr>
<tr>
<td>Fees &amp; Assessments Revenue*</td>
<td>24.9</td>
<td>28.2</td>
<td>(3.3)</td>
<td></td>
</tr>
<tr>
<td>Fees &amp; Assessments Expense</td>
<td>$14.7</td>
<td>$16.3</td>
<td>$(1.6)</td>
<td>FERC Fees &amp; Assessments expense is estimated based on prior year assessment plus a growth rate. The current year run rate is adjusted once the annual bill is received in June, causing variance to budget.</td>
</tr>
</tbody>
</table>

*Total Fees & Assessments revenue also includes annual non-load dues, which are $0.4 million for both the 2013 Forecast and Budget.
The graph and table above highlight the range of variance between SPP’s actual and budgeted Net Revenue Requirement (NRR) by year. As SPP’s NRR has increased over the years, the variances between actual and budget remain relatively small.
Load Variance Sensitivity

Rate Sensitivity to Load Variances

This graph depicts the impact on SPP’s admin fee due to variances in expected billing determinants. SPP has estimated its billing determinants to be 348.2 MWh for 2014. With a Net Revenue Requirement (NRR) of $132.6, SPP recommends its administrative fee to be $0.381 per MWh resulting in an estimated year ending operating cash balance of $4.6 million.

Assuming NRR remained the same and billing determinants were estimated at 355.1 MWh, a 2% increase, SPP could recommend an administrative fee of $0.370, but would have approximately $3.4 million in operating cash at the end of 2014. If billing determinants were estimated a 4% increase, SPP could change the administrative fee recommendation to $0.365 and would expect to have approximately $4.2 million in operating cash at the end of 2014. The results are reversed if billing determinants are estimated at less than 348.2 MWh.
## Prior Year Budget Comparisons ($ millions)

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<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td><strong>Net Revenue Required Estimations</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008 Budget - NRR Estimations</td>
<td>$61.5</td>
<td>$64.5</td>
<td>$71.2</td>
<td></td>
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<tr>
<td>2009 Budget - NRR Estimations</td>
<td>$56.5</td>
<td>$68.4</td>
<td>$75.1</td>
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<td>2010 Budget - NRR Estimations</td>
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<td>$94.9</td>
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<td>2011 Budget - NRR Estimations</td>
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<td>$86.7</td>
<td>$94.6</td>
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<td>2012 Budget - NRR Estimations</td>
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<td>$89.6</td>
<td>$98.6</td>
<td>$113.6</td>
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<td>2013 Budget - NRR Estimations</td>
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<td>$121.8</td>
<td>$141.4</td>
<td>$145.0</td>
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<tr>
<td>2014 Budget - NRR Estimations</td>
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<td></td>
<td>$132.6</td>
<td>$148.4</td>
<td>$145.2</td>
<td></td>
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<tr>
<td><strong>Actual NRR</strong></td>
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<td>$59.8</td>
<td>$63.5</td>
<td>$75.8</td>
<td>$86.1</td>
<td>$120.8</td>
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<td><strong>Billing Unit Estimations</strong></td>
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<tr>
<td>2008 Budget - Billing Units Estimations</td>
<td>312.5</td>
<td>319.1</td>
<td>325.8</td>
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<tr>
<td>2009 Budget - Billing Units Estimations</td>
<td>331.4</td>
<td>346.4</td>
<td>353.4</td>
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<tr>
<td>2010 Budget - Billing Units Estimations</td>
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<td>338.1</td>
<td>342.7</td>
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<tr>
<td>2011 Budget - Billing Units Estimations</td>
<td>343.0</td>
<td>345.0</td>
<td>349.8</td>
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<tr>
<td>2012 Budget - Billing Units Estimations</td>
<td>353.5</td>
<td>359.8</td>
<td>366.3</td>
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<td>2013 Budget - Billing Units Estimations</td>
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<tr>
<td><strong>Actual Billing Units</strong></td>
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<td>329.6</td>
<td>341.4</td>
<td>361.0</td>
<td>358.1</td>
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<td><strong>Administrative Fee Estimations</strong></td>
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<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>2008 Budget - Admin Fee Estimations</td>
<td>$0.190</td>
<td>$0.200</td>
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<td></td>
<td></td>
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<tr>
<td>2009 Budget - Admin Fee Estimations</td>
<td>$0.170</td>
<td>$0.170</td>
<td>$0.170</td>
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<tr>
<td>2010 Budget - Admin Fee Estimations</td>
<td>$0.195</td>
<td>$0.270</td>
<td>$0.280</td>
<td></td>
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<td></td>
</tr>
<tr>
<td>2011 Budget - Admin Fee Estimations</td>
<td>$0.210</td>
<td>$0.255</td>
<td>$0.280</td>
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<td></td>
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<td></td>
</tr>
<tr>
<td>2012 Budget - Admin Fee Estimations</td>
<td>$0.255</td>
<td>$0.280</td>
<td>$0.300</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>2013 Budget - Admin Fee Estimations</td>
<td>$0.338</td>
<td>$0.380</td>
<td>$0.379</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>2014 Budget - Admin Fee Estimations</td>
<td></td>
<td>$0.381</td>
<td>$0.426</td>
<td>$0.417</td>
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<td><strong>Actual Admin Fee</strong></td>
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<td>$0.182</td>
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<td>$0.222</td>
<td>$0.238</td>
<td>$0.337</td>
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This table attempts to quantify the year-to-year changes in SPP’s three year projections made during each budget cycle as required by the membership agreement. Accuracy of these projections can be significantly influenced by both internal and external pressures such as board and committee directives, incremental membership, environmental factors, etc.
Southwest Power Pool, Inc.
FINANCE COMMITTEE
Recommendation to the Board of Directors
October 29, 2013

2014 Administrative and Assessment Fee Rate

Organizational Roster
The following persons are members of the Finance Committee:

Harry Skilton  Director
Larry Altenbaumer  Director
Coleen Wells  Kansas Electric Power Coop
Mike Wise  Golden Spread Electric Coop
Sandra Bennett  American Electric Power
Kelly Harrison  Westar Energy

Background
Section 8.4 of the SPP Bylaws requires SPP to annually develop an assessment rate based on budgeted expenditures for the upcoming fiscal year and estimated billing determinants for that year.

Analysis
The 2014 SPP operating budget indicates a net revenue requirement ("NRR") for the year of $132.6 million (after funding $10 million in current maturities with new debt proceeds) and estimated billing determinants of 348,179,835 MWh. The rate is determined by dividing the NRR by the estimated billing determinants which results in a rate of 38.1¢/MWh. NRR is derived by adjusting SPP’s gross cash outflows (exclusive of capital expenditures) by all non administrative fee revenue forecast to be earned in the year. The billing determinants are calculated by analyzing the current year to date transmission usage and estimating usage through the remainder of the year.

Billing determinants are estimated based on the billing criteria detailed in the SPP tariff. Presently, network integration transmission service is charged the SPP schedule 1A administrative fee based on the average 12 monthly peaks from the previous year; point-to-point transmission service is charged the SPP schedule 1A administrative fee based on the reserved transmission capacity. Through August 2013, SPP has realized year-over-year decline in average monthly peaks of 3.12% which will result in approximately 3% reduction in billing units available in 2014 against which the schedule 1A administrative fee is charged.

<table>
<thead>
<tr>
<th>2012 NITS (12 CP in MW)</th>
<th>2013 Growth Rate</th>
<th>Est 2013 NITS</th>
<th>Hrs/Year</th>
<th>Est MWh</th>
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<tr>
<td>36,296.45</td>
<td>-3.00%</td>
<td>35,207.56</td>
<td>8,760</td>
<td>308,418,195</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>39,761,640 Est Point-to-Point</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>348,179,835</td>
</tr>
</tbody>
</table>

The SPP tariff presently defines the billing determinants for network integration transmission service as the prior year peak. This definition leaves SPP open to potential meaningful variances in load from one year to the next; which can result in greater volatility in the schedule 1A administrative fee rate. SPP reviewed the impact if the network integration transmission service billing determinants were based on a simple three year average of monthly system peaks. The analysis indicated the volatility...
of the billing determinants could be reduced, though the magnitude of the smoothing was rather minor due to the average volatility of the peaks being +/- 3%. The total amounts paid by network integration transmission customers didn’t change meaningfully (see attached summary analysis).

Recommendation

The Finance Committee recommends the SPP Board of Directors establish an assessment rate and tariff administrative fee (schedule 1-A) of 38.1¢/MWh beginning on January 1, 2014.

Approved: Finance Committee October 15, 2013

Action Requested: Approve Recommendation
Southwest Power Pool, Inc.

FINANCE COMMITTEE

Recommendation to the Board of Directors

October 29, 2013

2014 Financing

Organizational Roster

The following persons are members of the Finance Committee:

Harry Skilton               Director
Larry Altenbaumer           Director
Coleen Wells                Kansas Electric Power Coop
Mike Wise                   Golden Spread Electric Coop
Sandra Bennett              American Electric Power
Kelly Harrison              Westar Energy

Background

SPP’s term debt structure as of the end of September 2013 was as follows:

<table>
<thead>
<tr>
<th>Due Date</th>
<th>Rate</th>
<th>Original</th>
<th>Current</th>
<th>Funding Year</th>
<th>Lender</th>
<th>Primary Purpose</th>
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<tbody>
<tr>
<td>2014 Sr. Notes</td>
<td>5.61%</td>
<td>$30</td>
<td>$7</td>
<td>2007</td>
<td>Bank</td>
<td>Capital projects from 2006-2008</td>
</tr>
<tr>
<td>2016 Sr. Notes</td>
<td>5.45%</td>
<td>$30</td>
<td>$17</td>
<td>2009</td>
<td>Bank</td>
<td>Capital projects from 2008-2011</td>
</tr>
<tr>
<td>2024 Sr. Notes (C)</td>
<td>3.55%</td>
<td>$70</td>
<td>$70</td>
<td>2011</td>
<td>Insurance</td>
<td>Integrated Marketplace</td>
</tr>
<tr>
<td>2024 Sr. Notes (D1)</td>
<td>3.00%</td>
<td>$50</td>
<td>$50</td>
<td>2012</td>
<td>Insurance</td>
<td>Integrated Marketplace</td>
</tr>
<tr>
<td>2024 Sr. Notes (D2)</td>
<td>3.25%</td>
<td>$50</td>
<td>$50</td>
<td>2012</td>
<td>Insurance</td>
<td>Capital projects from 2012 - 2014</td>
</tr>
<tr>
<td>2027 Sr. Notes</td>
<td>6.36%</td>
<td>$5</td>
<td>$4</td>
<td>2007</td>
<td>Bank</td>
<td>Maumelle Ops Center</td>
</tr>
<tr>
<td>2042 Sr. Notes (A &amp; B)</td>
<td>4.82%</td>
<td>$65</td>
<td>$64</td>
<td>2010</td>
<td>Insurance</td>
<td>Corporate Campus</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td></td>
<td><strong>$300</strong></td>
<td><strong>$262</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

All notes are unsecured except for the 2027 Sr. Notes, which are secured by a mortgage on SPP’s Maumelle, AR operations facility. SPP also has a $30 million unsecured revolving line of credit maturing in June 2016. The revolving line currently has $0 advanced. Pricing of draws against the line of credit are variable based on SPP’s credit rating by Fitch Ratings. Currently any draws under the revolving facility would be priced at LIBOR + 1.25%.

SPP’s 2014-16 capital expenditure program identifies expenditures of $61.8 million which require funding. In an effort to minimize the expected increase in 2014 schedule 1A administrative fee expense, SPP’s Finance Committee discussed funding an additional $10 million in term debt to offset increased term debt maturities in 2014.

Analysis

Since 2007, SPP has implemented an aggressive capital expenditure program intended to ensure competitive service offerings to its customers and is able to do so in a highly reliable and secure manner. Two significant projects, the Integrated Marketplace and the SPP campus, have resulted in the majority of the $264 million spent between 2008–13.

The Integrated Marketplace project is scheduled to be completed and implemented by March 1, 2014. There are several follow-on projects related to the Integrated Marketplace which were either deferred from the initial implementation, added to
enhance the functionality of the initial implementation, or required by regulatory authorities. These projects are referred to as “Post-Go-Live” projects.

Ten projects are classified as Integrated Marketplace Post Go-Live projects. Market to Market, Long Term Congestion Rights (LTCR), and Regulation Compensation projects were mandated by FERC. The Enhanced Combined Cycle project was requested by members and is expected to be authorized by the Markets and Operations Policy Committee (MOPC) in October 2013.

Another anticipated FERC-mandated project is GFA Carve Out. Updated estimates for Post Go-Live project costs were developed utilizing information available during the 2014 project budgeting cycle.

In addition to the Post-Go-Live projects, other capital projects include several on-going projects which are dominated by the planned upgrade of the transmission settlement system and implementation of the training and testing simulated environment; and SPP’s needs to maintain and refresh its system hardware (approx. $7.8 million/year). A summary of the identified capital expenditures is provided below, as well as a breakdown of the impact to the administrative fee of each over the life of the asset:

<table>
<thead>
<tr>
<th>Project Summary</th>
<th>Revised Estimate</th>
<th>Contingency</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market to Market</td>
<td>$7.0</td>
<td>$0.0</td>
<td></td>
<td>$7.0</td>
</tr>
<tr>
<td>Long-Term Congestion Rights (LTCRs)</td>
<td>1.8</td>
<td>2.5</td>
<td>(1)</td>
<td>4.3</td>
</tr>
<tr>
<td>Enhanced Combined Cycle</td>
<td>2.4</td>
<td>2.2</td>
<td>(2)</td>
<td>4.6</td>
</tr>
<tr>
<td>Regulation Compensation</td>
<td>3.2</td>
<td>0.0</td>
<td></td>
<td>3.2</td>
</tr>
<tr>
<td>AFC Granularity Changes for TSRs</td>
<td>1.4</td>
<td>0.0</td>
<td></td>
<td>1.4</td>
</tr>
<tr>
<td>IT Environments Buildout for Marketplace</td>
<td>0.6</td>
<td>0.0</td>
<td></td>
<td>0.6</td>
</tr>
<tr>
<td>Grandfather Agreement Carve Out (GFA)</td>
<td>0.3</td>
<td>0.0</td>
<td></td>
<td>0.3</td>
</tr>
<tr>
<td>Pseudo Tie In/Out</td>
<td>0.2</td>
<td>0.0</td>
<td></td>
<td>0.2</td>
</tr>
<tr>
<td>Marketplace Date for MPs Post Go-Live</td>
<td>0.1</td>
<td>0.0</td>
<td></td>
<td>0.1</td>
</tr>
<tr>
<td>Sunset Clause for Load Submittal for Legacy Based Systems</td>
<td>0.2</td>
<td>0.0</td>
<td></td>
<td>0.2</td>
</tr>
<tr>
<td><strong>Total Market Post Go-Live Projects</strong></td>
<td><strong>$16.9</strong></td>
<td><strong>$4.8</strong></td>
<td></td>
<td><strong>$21.7</strong></td>
</tr>
</tbody>
</table>

(1) Additional contingency for changes to the transmission planning and the Credit Management System

(2) Approximate 50% capital contingency for Enhanced Combined Cycle
The debt on SPP’s books has funded the acquisition of assets utilized by SPP to carry out its functions. These assets consist primarily of highly-customized software applications, real estate, computer equipment, and furniture & fixtures. SPP depreciates these assets on a straight-line basis ranging from three years (for computer equipment and software) to twenty years (for real estate structures). The real useful life of these assets rarely corresponds directly with the depreciation schedule. The table below attempts to contrast the depreciation schedule with the real expected useful life of the assets.

<table>
<thead>
<tr>
<th>Asset</th>
<th>Depreciation Schedule</th>
<th>Expected Useful Life</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buildings</td>
<td>20 years</td>
<td>40 years</td>
</tr>
<tr>
<td>Market Software</td>
<td>3 years</td>
<td>10 years</td>
</tr>
<tr>
<td>Furniture &amp; Fixtures</td>
<td>5 years</td>
<td>10 years</td>
</tr>
<tr>
<td>Equipment</td>
<td>3 years</td>
<td>4 years</td>
</tr>
<tr>
<td>Software</td>
<td>3 years</td>
<td>5 years</td>
</tr>
</tbody>
</table>
SPP has summarized the cost basis of the assets as either five-year assets, ten-year assets, or long-term assets and then compared these categories to the outstanding balance of long-term debt on SPP’s books. The analysis assumes a start date of January 1, 2014. The chart below compares SPP’s assets with lives of ten years or less with outstanding debt with maturities of ten years or less.

The following chart compares SPP’s long-lived assets (real estate holdings) with outstanding debt with maturities of more than ten years (primarily thirty-year notes).

SPP forecasts a need to borrow an additional $70 million in long-term debt to fund identified capital expenditures for the 2014 – 2016 period. The assets acquired are expected to have a weighted average useful life of 6.5 years.

<table>
<thead>
<tr>
<th>Asset</th>
<th>Cost Basis</th>
<th>Useful Life</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equipment</td>
<td>$15.8</td>
<td>4</td>
</tr>
<tr>
<td>Software</td>
<td>$23.7</td>
<td>5</td>
</tr>
<tr>
<td>Post Go-Live</td>
<td>$21.7</td>
<td>10</td>
</tr>
<tr>
<td><strong>Weighted Average Useful Life</strong></td>
<td></td>
<td>6.5</td>
</tr>
</tbody>
</table>
SPP has a number of alternatives for financing, the most likely of which are shown below:

a) Fund $60 million @ 3%, 7-year note, 1 year interest only, 6 year principal payments of $10 million/year
b) Fund $60 million @ 4%, 12-year note, 2 year interest only, 10 year principal payments of $6 million/year
c) Fund $70 million @4%, 12-year note, 2 year interest only, 10 year principal payments of $7 million/year

Option C will use the additional $10 million in funding to retire a like amount of existing debt in 2014 without including that debt retirement in the 2014 schedule 1A recoveries. The three funding alternatives are expected to have the following incremental impact on SPP’s administrative fee rate assuming a flat load of 350 million MWh for simplicity.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Option A</td>
<td>$0.005</td>
<td>$0.034</td>
<td>$0.033</td>
<td>$0.032</td>
<td>$0.031</td>
<td>$0.030</td>
<td>$0.029</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
</tr>
<tr>
<td>Option B</td>
<td>$0.007</td>
<td>$0.024</td>
<td>$0.023</td>
<td>$0.023</td>
<td>$0.022</td>
<td>$0.021</td>
<td>$0.020</td>
<td>$0.019</td>
<td>$0.019</td>
<td>$0.019</td>
<td>$0.018</td>
</tr>
<tr>
<td>Option C</td>
<td>($0.021)</td>
<td>$0.028</td>
<td>$0.027</td>
<td>$0.026</td>
<td>$0.026</td>
<td>$0.025</td>
<td>$0.024</td>
<td>$0.023</td>
<td>$0.022</td>
<td>$0.022</td>
<td>$0.021</td>
</tr>
</tbody>
</table>

SPP began discussions with potential lenders in July to determine interest from the commercial banks for a traditional bank financed deal as well as with the private placement investors.

Recommendation

Approve the recommendation of the SPP Finance Committee to issue up to $70 million in debt securities to fund SPP’s capital expenditure program through 2016. Said approval was subject to the following conditions:

1. Authorize issuance of up to $70 million in secured and unsecured notes with maturities of up to 12 years;
2. Authorize appropriate regulatory filings for the issuance of up to $70 million in secured and unsecured notes with maturities of up to 12 years to be issued within 24 months of receiving regulatory approval;
3. Authorize SPP Finance Committee to oversee negotiation, final approval of terms and conditions, and authorization to execute up to $70 million in secured and unsecured notes with maturities of up to 12 years;
4. Authorize the SPP President and CFO to jointly execute notes and agreements for the issuance of up to $70 million in secured and unsecured notes with maturities of up to 12 years, upon final authorization of the SPP Finance Committee.

Approved: Finance Committee October 15, 2013

Action Requested: Approve Recommendation
Finance Committee Report

October 29, 2013

Harry Skilton – Chair

SPP Finance Committee Roster

Harry Skilton, Chair
Larry Altenbaumer, Vice Chair
Mike Wise
Coleen Wells
Sandra Bennett
Kelly Harrison

Director
Director
Golden Spread
KEPCo
AEP
Westar
2014 Budget Assumptions

- Zero-Based Budget
- Vacancy assumption of 2%
- Merit increases of 2.4%
- Promotions 0.75%
- Decrease in load projection by 3.1%
- Principal Repayments for 2014-2016: $13, $24, & $21

2014 Budget Metrics

(In Millions of Dollars except Billing Determinants, Rates, and Headcount)

<table>
<thead>
<tr>
<th></th>
<th>2013 Budget</th>
<th>2013 Fcst</th>
<th>2014 Budget</th>
<th>Fav /(Unfav) Variances</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Revenue Required</td>
<td>$121.8</td>
<td>$120.8</td>
<td>$132.6</td>
<td>$1.0 ($11.8)</td>
</tr>
<tr>
<td>Billing Units (Thousand GWh)</td>
<td>360.9</td>
<td>358.1</td>
<td>348.2</td>
<td>(2.8) (9.9)</td>
</tr>
<tr>
<td>Calculated Admin Fee/GWh</td>
<td>33.8¢</td>
<td>33.7¢</td>
<td>38.1¢</td>
<td>0.1¢ (4.4¢)</td>
</tr>
<tr>
<td>Capital Expenditures</td>
<td>$35.8</td>
<td>$41.4</td>
<td>$37.1</td>
<td>($5.6) $4.3</td>
</tr>
<tr>
<td>Year Ending Headcount</td>
<td>603</td>
<td>596</td>
<td>598</td>
<td>7 (2)</td>
</tr>
</tbody>
</table>
### Net Revenue Requirement Components

<table>
<thead>
<tr>
<th></th>
<th>2013 Budget</th>
<th>2013 Fcst</th>
<th>2014 Budget</th>
<th>Favorable/Unfavorable Variances</th>
<th>2013 Fcst to '13 Budget</th>
<th>2014 Bud to '13 Fcst</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Expenses</td>
<td>$162.6</td>
<td>$157.4</td>
<td>$200.7</td>
<td>$5.3 ($43.3)</td>
<td>0.0 (0.3)</td>
<td>(0.6) 30.0</td>
</tr>
<tr>
<td>+ Debt Service *</td>
<td>12.7</td>
<td>12.7</td>
<td>13.0</td>
<td>0.0</td>
<td>(0.3)</td>
<td></td>
</tr>
<tr>
<td>- Depreciation and Amort</td>
<td>(20.3)</td>
<td>(19.7)</td>
<td>(49.7)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gross Revenue Required</td>
<td>$155.0</td>
<td>$150.4</td>
<td>$164.0</td>
<td>$4.6 ($13.6)</td>
<td>(1.3) 1.7</td>
<td>(0.4) 0.6</td>
</tr>
<tr>
<td>- NERC revenue</td>
<td>(11.5)</td>
<td>(10.2)</td>
<td>(11.8)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- FERC fee expense</td>
<td>(16.3)</td>
<td>(14.7)</td>
<td>(15.3)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Other Revenues</td>
<td>(5.4)</td>
<td>(4.7)</td>
<td>(4.2)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Revenue Required</td>
<td>$121.8</td>
<td>$120.8</td>
<td>$132.6</td>
<td>$1.0 ($11.8)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* Note: Total 2014 scheduled debt service is $23 million, reduced by $10 million in current maturities funded by new debt proceeds.

### Operating Expenditure Components

<table>
<thead>
<tr>
<th></th>
<th>2013 Budget</th>
<th>2013 Fcst</th>
<th>2014 Budget</th>
<th>Favorable/Unfavorable Variances</th>
<th>2013 Fcst to '13 Budget</th>
<th>2014 Bud to '13 Fcst</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salary &amp; Benefits</td>
<td>$77.4</td>
<td>$77.7</td>
<td>$82.2</td>
<td>($0.3) ($3.6)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assessments &amp; Fees</td>
<td>16.0</td>
<td>15.3</td>
<td>14.3</td>
<td>0.7</td>
<td>1.0</td>
<td></td>
</tr>
<tr>
<td>Services</td>
<td>16.0</td>
<td>15.3</td>
<td>14.3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depreciation &amp; Amort</td>
<td>20.3</td>
<td>19.7</td>
<td>49.7</td>
<td>(0.4) (30.0)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maintenance</td>
<td>10.5</td>
<td>11.0</td>
<td>15.9</td>
<td>(1.5) (4.9)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interest Expense</td>
<td>7.8</td>
<td>7.7</td>
<td>10.9</td>
<td>0.0</td>
<td>(3.1)</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>14.4</td>
<td>11.4</td>
<td>13.1</td>
<td>3.0</td>
<td>(1.8)</td>
<td></td>
</tr>
<tr>
<td>Operating Expenses</td>
<td>$162.6</td>
<td>$157.4</td>
<td>$201.4</td>
<td>$5.2 ($44.0)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- Salary and Benefits increases:
  - Vacancy changed from 6% (2013 budget) to 2% (2014 budget)
  - Vacancy run-rate for 2013 forecast is 4%
  - Claims experience for health benefits
- Increased interest expense for add’l financing
- Increased maintenance for new market systems
### Incremental Positions

<table>
<thead>
<tr>
<th>Headcount by Division</th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations</td>
<td>158</td>
<td>157</td>
<td>157</td>
</tr>
<tr>
<td>Information Technology</td>
<td>143</td>
<td>144</td>
<td>144</td>
</tr>
<tr>
<td>Engineering</td>
<td>81</td>
<td>78</td>
<td>79</td>
</tr>
<tr>
<td>Process Integrity</td>
<td>47</td>
<td>47</td>
<td>47</td>
</tr>
<tr>
<td>Finance</td>
<td>40</td>
<td>39</td>
<td>39</td>
</tr>
<tr>
<td>Compliance, Communications, and MMU</td>
<td>31</td>
<td>30</td>
<td>30</td>
</tr>
<tr>
<td>Corporate Services</td>
<td>29</td>
<td>29</td>
<td>29</td>
</tr>
<tr>
<td>Regulatory Policy and Legal</td>
<td>25</td>
<td>25</td>
<td>26</td>
</tr>
<tr>
<td>Officers</td>
<td>11</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Market Development</td>
<td>6</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>Subtotal</td>
<td>571</td>
<td>565</td>
<td>567</td>
</tr>
<tr>
<td>Regional Entity</td>
<td>32</td>
<td>31</td>
<td>31</td>
</tr>
<tr>
<td><strong>Total Headcount</strong></td>
<td><strong>603</strong></td>
<td><strong>596</strong></td>
<td><strong>598</strong></td>
</tr>
</tbody>
</table>

### SPP Staffing Trend

**Average tenure for SPP staff for 2011-2013 is:** 5.4yrs, 5.6yrs, and 6.1yrs, respectively
Operating Expenditure Components

<table>
<thead>
<tr>
<th></th>
<th>2013 Budget</th>
<th>2013 Fcst</th>
<th>2014 Budget</th>
<th>2013 Fcst to '13 Bud</th>
<th>Bud to '13 Fcst</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salary &amp; Benefits</td>
<td>$77.4</td>
<td>$77.7</td>
<td>$82.2</td>
<td>($0.3)</td>
<td>($3.6)</td>
</tr>
<tr>
<td>Assessments &amp; Fees</td>
<td>16.3</td>
<td>14.7</td>
<td>15.3</td>
<td>0.6</td>
<td>0.4</td>
</tr>
<tr>
<td>Services</td>
<td>16.0</td>
<td>15.3</td>
<td>14.3</td>
<td>0.7</td>
<td>1.0</td>
</tr>
<tr>
<td>Depreciation &amp; Amort</td>
<td>20.3</td>
<td>19.7</td>
<td>49.7</td>
<td>(0.4)</td>
<td>(30.0)</td>
</tr>
<tr>
<td>Maintenance</td>
<td>10.5</td>
<td>11.0</td>
<td>15.9</td>
<td>(1.5)</td>
<td>(4.9)</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>7.8</td>
<td>7.7</td>
<td>10.9</td>
<td>0.0</td>
<td>(3.1)</td>
</tr>
<tr>
<td>Other</td>
<td>14.4</td>
<td>11.4</td>
<td>13.1</td>
<td>3.0</td>
<td>(1.8)</td>
</tr>
<tr>
<td><strong>Operating Expenses</strong></td>
<td>$162.6</td>
<td>$157.4</td>
<td>$201.4</td>
<td>$5.2</td>
<td>($44.0)</td>
</tr>
</tbody>
</table>

- Salary and Benefits increases:
  - Vacancy changed from 6% (2013 budget) to 2% (2014 budget)
  - Vacancy run-rate for 2013 forecast is 4%
  - Claims experience for health benefits
- Increased interest expense for add'l financing
- Increased maintenance for new market systems

Capital Expenditures

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Other CapEx Excluding IM</td>
<td>$3</td>
<td>$16</td>
<td>$9</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Building</td>
<td>$10</td>
<td>$42</td>
<td>$32</td>
<td></td>
<td></td>
<td></td>
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<td>Carry Over</td>
<td></td>
<td>$3</td>
<td>$2</td>
<td>$9</td>
<td>$0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New Projects '14-'16</td>
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<td>$1</td>
<td>$0</td>
<td>$0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IT / Ops Foundation &amp; Refresh</td>
<td>$11</td>
<td>$7</td>
<td>$5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Post Go-Live</td>
<td></td>
<td>$2</td>
<td>$18</td>
<td>$3</td>
<td>$0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Integrated Marketplace</td>
<td>$9</td>
<td>$22</td>
<td>$42</td>
<td>$36</td>
<td>$6</td>
<td>$0</td>
<td>$0</td>
</tr>
</tbody>
</table>
## Capital Expenditures

### 2014 Capital Projects

<table>
<thead>
<tr>
<th>Project</th>
<th>2014 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Original Go-Live</strong></td>
<td></td>
</tr>
<tr>
<td>Integrated Marketplace Go-Live (Includes CBA)</td>
<td>$5.8</td>
</tr>
<tr>
<td><strong>Post Go-Live</strong></td>
<td></td>
</tr>
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<td>Market to Market</td>
<td>5.9</td>
</tr>
<tr>
<td>Regulation Compensation</td>
<td>2.4</td>
</tr>
<tr>
<td>Long-Term Congestion Rights (LTCRs)</td>
<td>4.0</td>
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<tr>
<td>Enhanced Combined Cycle</td>
<td>4.3</td>
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<tr>
<td>Other</td>
<td>0.9</td>
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<tr>
<td><strong>Total Market Post Go-Live Projects</strong></td>
<td><strong>17.5</strong></td>
</tr>
<tr>
<td><strong>IT / Ops Foundation</strong></td>
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<td>IT Network Telecom</td>
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<td>IT Systems Foundation</td>
<td>3.1</td>
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<td>IT Applications Foundation</td>
<td>1.5</td>
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<tr>
<td>Ops Foundation</td>
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<tr>
<td><strong>Total IT / Ops Foundation</strong></td>
<td><strong>11.1</strong></td>
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<tr>
<td><strong>Carryover / New Projects</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>$2.8</strong></td>
</tr>
<tr>
<td><strong>Total 2014 Capital Project Budget</strong></td>
<td><strong>$37.1</strong></td>
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</tbody>
</table>

### Existing Principal Payment Obligations

The bar chart illustrates the existing principal payment obligations from 2012 to 2018, broken down by Integrated Marketplace, Corporate Campus, Maumelle Facility, Other CapEx, and Marketplace & Future CapEx.
Value of Fixed Assets vs. Debt

### Asset vs. Debt Values

![Graph showing asset vs. debt values over time.](image)

**Administrative Fee**

<table>
<thead>
<tr>
<th>Administrative Fee ($ millions)</th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
<th>2014 Prior Year Estimate (2)</th>
</tr>
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<tbody>
<tr>
<td>Operating Expenses</td>
<td>$162.6</td>
<td>$157.4</td>
<td>$200.7</td>
<td>$199.4</td>
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<tr>
<td>Debt Service</td>
<td>12.7</td>
<td>12.7</td>
<td>13.0</td>
<td>23.0</td>
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<tr>
<td>Less: Depreciation/Amortization</td>
<td>(20.3)</td>
<td>(19.7)</td>
<td>(49.7)</td>
<td>(47.0)</td>
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<tr>
<td>Gross Revenue Requirement</td>
<td>$155.0</td>
<td>$150.4</td>
<td>$164.0</td>
<td>$175.4</td>
</tr>
<tr>
<td>Less:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NERC revenue</td>
<td>(11.5)</td>
<td>(10.2)</td>
<td>(11.8)</td>
<td>(11.9)</td>
</tr>
<tr>
<td>FERC fee expense</td>
<td>(16.3)</td>
<td>(14.7)</td>
<td>(15.3)</td>
<td>(17.2)</td>
</tr>
<tr>
<td>Other Revenues</td>
<td>(5.4)</td>
<td>(4.7)</td>
<td>(4.2)</td>
<td>(4.8)</td>
</tr>
<tr>
<td>Net Revenue Requirement</td>
<td>$121.8</td>
<td>$120.8</td>
<td>$132.6</td>
<td>$141.4</td>
</tr>
<tr>
<td>Billing Determinant (MWh millions) (1)</td>
<td>360.9</td>
<td>358.1</td>
<td>348.2</td>
<td>371.7</td>
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<tr>
<td>Calculated Admin Fee/MWh</td>
<td>$0.338</td>
<td>$0.337</td>
<td>$0.381</td>
<td>$0.380</td>
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<tr>
<td>Proposed Admin Fee/MWh</td>
<td>$0.315</td>
<td>$0.315</td>
<td>$0.381</td>
<td>$0.370</td>
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<tr>
<td>Current Tariff Admin Fee Cap</td>
<td>$0.350</td>
<td>$0.350</td>
<td>$0.390</td>
<td>$0.390</td>
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(1) Defined as coincident peak for network service and capacity for point to point service in MWh.

(2) Refers to the 2014 estimate made during 2013 budget presentation.
Transmission Load Components

<table>
<thead>
<tr>
<th>Monthly Coincident Peak</th>
<th>2012</th>
<th>2013</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan-12</td>
<td>31,857</td>
<td>32,523</td>
<td>2.1%</td>
</tr>
<tr>
<td>Feb-12</td>
<td>30,694</td>
<td>31,090</td>
<td>1.3%</td>
</tr>
<tr>
<td>Mar-12</td>
<td>28,413</td>
<td>30,325</td>
<td>6.7%</td>
</tr>
<tr>
<td>Apr-12</td>
<td>32,445</td>
<td>29,476</td>
<td>-9.2%</td>
</tr>
<tr>
<td>May-12</td>
<td>37,558</td>
<td>34,672</td>
<td>-7.7%</td>
</tr>
<tr>
<td>Jun-12</td>
<td>45,673</td>
<td>43,746</td>
<td>-4.2%</td>
</tr>
<tr>
<td>Jul-12</td>
<td>47,317</td>
<td>44,749</td>
<td>-5.4%</td>
</tr>
<tr>
<td>Aug-12</td>
<td>46,900</td>
<td>44,900</td>
<td>-4.3%</td>
</tr>
<tr>
<td>Sep-12</td>
<td>43,464</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oct-12</td>
<td>29,311</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov-12</td>
<td>28,683</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dec-12</td>
<td>31,388</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jan-Aug Avg</td>
<td>37,607</td>
<td>36,435</td>
<td>-3.1%</td>
</tr>
</tbody>
</table>

- 2014 Admin Fee revenues based on average monthly coincident transmission peaks
- Average decrease of 3.1% over Jan-Aug 2013

<table>
<thead>
<tr>
<th>2014 Budget</th>
<th>Yr Over Yr Change</th>
<th>Coincident peak</th>
<th>Hrs per month</th>
<th># of months</th>
<th>Transmission volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>NITS</td>
<td>-3.1%</td>
<td>35,208</td>
<td>730</td>
<td>12</td>
<td>308,418,195</td>
</tr>
<tr>
<td>PTP</td>
<td>2.0%</td>
<td>4,539</td>
<td>730</td>
<td>12</td>
<td>39,761,640</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>39,747</td>
<td></td>
<td></td>
<td>348,179,835</td>
</tr>
</tbody>
</table>

- 2014 transmission volume is 348M MWh
- 2013 budget 360M MWh
- Prior year 2014 projection assumed 370M MWh

SPP Administrative Fee History & Projections
Comparison of Prior Year Budget Estimates

Administrative Cost Projections

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
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<th></th>
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</thead>
<tbody>
<tr>
<td>2008 Budget</td>
<td>$0.190</td>
<td>$0.200</td>
<td>$0.200</td>
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<tr>
<td>2009 Budget</td>
<td>$0.170</td>
<td>$0.170</td>
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<tr>
<td>2010 Budget</td>
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<td>$0.270</td>
<td>$0.280</td>
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<tr>
<td>2011 Budget</td>
<td>$0.210</td>
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<td>$0.280</td>
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<td>2014 Budget</td>
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<td>$0.417</td>
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</table>

Approved Admin Fee Rate

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</thead>
<tbody>
<tr>
<td>2008 Budget</td>
<td>$0.190</td>
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<tr>
<td>2010 Budget</td>
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<tr>
<td>2014 Budget</td>
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<td></td>
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<td></td>
<td></td>
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</table>

Actual Cost per MWh

Changes from Prior 2014 Budget Projections

<table>
<thead>
<tr>
<th>Item</th>
<th>% of Change</th>
<th>Admin Fee Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>NRR 2014 Prior Projection *</td>
<td>$141.4</td>
<td>$38.0</td>
</tr>
<tr>
<td>Decrease in Billing Determinants</td>
<td></td>
<td>3.4</td>
</tr>
<tr>
<td>Reduction in Order 1000</td>
<td>0.7</td>
<td>(8%)</td>
</tr>
<tr>
<td>Change in NERC and FERC Funding</td>
<td>(0.2)</td>
<td>2%</td>
</tr>
<tr>
<td>Net Changes in Revenue</td>
<td>0.5</td>
<td>(6%)</td>
</tr>
<tr>
<td>Debt Repayment Reduction</td>
<td>(10.0)</td>
<td>113%</td>
</tr>
<tr>
<td>Increase in Interest Expense</td>
<td>1.7</td>
<td>(19%)</td>
</tr>
<tr>
<td>Changes in Salary &amp; Benefits</td>
<td>1.4</td>
<td>(16%)</td>
</tr>
<tr>
<td>Meetings</td>
<td>(0.6)</td>
<td>7%</td>
</tr>
<tr>
<td>Office &amp; Utilities</td>
<td>(0.9)</td>
<td>11%</td>
</tr>
<tr>
<td>Services Decrease</td>
<td>(1.5)</td>
<td>17%</td>
</tr>
<tr>
<td>Misc Other</td>
<td>0.6</td>
<td>(7%)</td>
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<tr>
<td>Net Changes in Expenses</td>
<td>($9.3)</td>
<td>106%</td>
</tr>
<tr>
<td>NRR 2014 Budget</td>
<td>$132.6</td>
<td>100%</td>
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* Calculated NRR from 2013 Budget Projections for 2014
RTO Comparison

SPP's costs and staffing estimates are based on 2014 budget projections to reflect full market functionality. Other RTOs are based on their 2012 audited financial statements.

SPP Finance Committee

2014 Budget

Finance Committee Recommendations

Approve the 2014 SPP operating and capital budgets as submitted.

Establish an assessment rate and tariff administrative charge rate (schedule 1A) of 38.1¢/MWh effective January 1, 2014.
Questions and Discussion

Maintenance Components

<table>
<thead>
<tr>
<th>Maintenance Expense ($ millions)</th>
<th>2013 Budget</th>
<th>2013 Forecast</th>
<th>2014 Budget</th>
<th>Prior 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Support-IT Foundation</td>
<td>5.97</td>
<td>6.02</td>
<td>7.83</td>
<td>5.90</td>
</tr>
<tr>
<td>Market</td>
<td>0.65</td>
<td>0.89</td>
<td>2.81</td>
<td>4.06</td>
</tr>
<tr>
<td>Leveraged Services</td>
<td>1.02</td>
<td>1.05</td>
<td>1.74</td>
<td>2.00</td>
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<tr>
<td>Reliability</td>
<td>1.27</td>
<td>1.25</td>
<td>1.40</td>
<td>1.32</td>
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<tr>
<td>Support-Project/Other</td>
<td>0.33</td>
<td>0.56</td>
<td>0.92</td>
<td>0.70</td>
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<tr>
<td>General Plant Maintenance</td>
<td>0.76</td>
<td>0.78</td>
<td>0.69</td>
<td>0.84</td>
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<tr>
<td>Transmission</td>
<td>0.47</td>
<td>0.46</td>
<td>0.47</td>
<td>0.47</td>
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<tr>
<td>Total</td>
<td>10.48</td>
<td>11.00</td>
<td>15.87</td>
<td>15.30</td>
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</table>
Southwest Power Pool, Inc.
MARKETS AND OPERATIONS POLICY COMMITTEE
Recommendation to the Board of Directors
TRR 104 & 110– Generation Interconnection Procedure Revisions
October 29, 2013

Organizational Roster
The following persons are members of the Regional Tariff Working Group:

Dennis Reed, WR (Chair)                Paul Malone, NPPD
Charles Locke, KCPL (Vice-Chair)       Walt Cecil, MoPSC
Richard Andrysik, LES                  Robert Pennybaker, AEP
Bill Dowling, Midwest Energy           Neil Rowland, KMEA
Luke Haner, OPPD                       Robert Shields, AECC
Tom Hestermann, Sunflower              Keith Tynes, ETEC
Rob Janssen, Dogwood                   John Varnell, Tenaska
David Kays, OGE                        Bary Warren, EDE
Lloyd Kolb, Golden Spread              Mitch Williams, WFEC
Tom Littleton, OMPA                     Brenda Fricano, SPP (Secretary)
Bernie Liu, Xcel

Background
Please see the TRR Recommendation Report for TRR’s 104 & 110 that were included in the MOPC October 15 - 16, 2013 background materials.

Analysis
Please see the TRR Recommendation Report for TRR’s 104 & 110 that were included in the MOPC October 15 - 16, 2012 background materials.

Recommendation
The MOPC recommends that the Board of Directors approve its request regarding Tariff Revision Requests TRR’s 104 & 110.

Action Requested: Approval of RTWG’s request on TRR’s 104 & 110.
APPROVED: MOPC

October 15-16, 2013

Passed as modified with four abstentions-Exelon, City of Coffeyville, Xcel Energy, & OPPD

<table>
<thead>
<tr>
<th>TRR Number</th>
<th>Description</th>
<th>RTWG Meeting Vote</th>
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<tbody>
<tr>
<td>104</td>
<td>Revisions to Attachment Y and addition of Addendum 5 to Attachment O to address Order 1000 regional compliance.</td>
<td>September 25, 2013 Approved unanimously</td>
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<tr>
<td>110</td>
<td>Revisions to Attachment Y and O to address Order 1000 regional compliance.</td>
<td>September 25, 2013 Approved unanimously</td>
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**Tariff Revision Request (TRR)**

<table>
<thead>
<tr>
<th>TRR Number</th>
<th>TRR Title</th>
<th>Order 1000 Compliance Revisions (Round 1)</th>
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<tr>
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<thead>
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<th>Cross Reference #</th>
<th>MPRR</th>
<th>BRR</th>
<th>Other (Specify)</th>
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**Sponsor**

<table>
<thead>
<tr>
<th>Name</th>
<th>Matt Binette</th>
</tr>
</thead>
<tbody>
<tr>
<td>E-mail Address</td>
<td><a href="mailto:binette@wrightlaw.com">binette@wrightlaw.com</a></td>
</tr>
<tr>
<td>Company</td>
<td>Wright &amp; Talisman</td>
</tr>
<tr>
<td>Phone Number</td>
<td>202-393-1200</td>
</tr>
<tr>
<td>Date</td>
<td>8/15/13</td>
</tr>
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</table>

**Tariff Section(s) Requiring Revision**

<table>
<thead>
<tr>
<th>Section No.</th>
<th>Titles</th>
<th>Tariff Version (effective date)</th>
</tr>
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<tbody>
<tr>
<td></td>
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</table>

**Requested Resolution**

- Normal
- Urgent (provided justification below for urgent request)

**Revision Description**

Revisions to Attachment Y §§ I.1, III.1.b.iii, III.2.c.vi, VI.3, and VI.4 and addition of Addendum 5 to Attachment O to address Order 1000 regional compliance.

**Reason for Revision**

On July 18, 2013, FERC issued its order addressing SPP’s compliance with the regional aspects of Order 1000. *Sw. Power Pool, Inc.*, 144 FERC ¶ 61,059 (2013). This TRR is the first of several that will address various requirements from the July 18 Order. These revisions address several compliance requirements that do not involve policy decisions by the Strategic Planning Committee Task Force on Order 1000.

**Stakeholder Approval Required (specify date and record outcome of vote; n/a for those stakeholders not required)**

- MWG (n/a)
- BPWG (n/a)
- TWG (n/a)
- ORWG (n/a)
- Other (specify) (n/a)
- RTWG – Approved – 9-25-2013
- MOPC
- Board of Directors
<table>
<thead>
<tr>
<th>Section</th>
<th>Answer</th>
<th>Notes</th>
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<tbody>
<tr>
<td>Legal Review Completed</td>
<td>Yes (Include any comments resulting from the review)</td>
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<tr>
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<td></td>
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<tr>
<td>Market Protocol Implications or Changes</td>
<td></td>
<td>Yes (Include a summary of impact and/or specific changes &amp; PRR #)</td>
</tr>
<tr>
<td></td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Business Practice Implications or Changes</td>
<td></td>
<td>Yes (Include a summary of impact and/or specific changes &amp; BPR #)</td>
</tr>
<tr>
<td></td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Criteria Implications or Changes</td>
<td>Yes (Include a summary of impact and/or specific changes)</td>
<td>This TRR does not require any changes to the Criteria, but the TRR incorporates language from Appendix 11 of the Criteria into Attachment O of the Tariff.</td>
</tr>
<tr>
<td></td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Other Corporate Documents Implications</td>
<td></td>
<td>Yes (Include which corporate documents)</td>
</tr>
<tr>
<td>(i.e., SPP By-Laws, Membership Agreement, etc.)</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Credit Implications</td>
<td></td>
<td>Yes (Include a summary of impact and/or specific changes)</td>
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<tr>
<td></td>
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<tr>
<td>Impact Analysis Required</td>
<td></td>
<td>Yes</td>
</tr>
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<td></td>
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</table>
Merchant Transmission Developer Interconnection

Other than for generation interconnections addressed by Attachment V of this Tariff, this Addendum 5 is applicable to Merchant Transmission Developers that request an interconnection to the Transmission System. For purposes of this Addendum 5, a Merchant Transmission Developer is an entity that assumes all financial responsibility for the development, construction and operation of the transmission facilities it seeks to interconnect to the Transmission System, does not seek regional cost allocation or cost recovery for such facilities under this Tariff, and does not intend to transfer functional control over such facilities to the Transmission Provider. Such entity Merchant Transmission Developers must comply with all requirements set forth in the SPP Criteria, including but not limited to providing the following information to the Transmission Provider, as required in Appendix 11 of the SPP Criteria:

Transmission Interconnection Review Data Checklist

1. **Primary contact and all affected parties’ contact information.**
2. **Overview of the proposed interconnection and its need.**
3. **Estimated or proposed in-service date.**
4. **List of all studies run by season.**
   a. **Power flow studies minimum requirements met.**
   b. **Short circuit studies minimum requirements met.**
   c. **Dynamics studies minimum requirements met.**
5. **Affected parties planning criteria, if applicable.**
6. **A detailed description of the proposed interconnection.**
   a. **In-service date**
b. Design information  
c. Ratings of the interconnection  
d. A geographic map of the interconnection area  
e. Electrical one-line diagrams of the facilities being connected.

7. Appropriate program files and program automation files to allow SPP staff to reproduce the studies performed.

8. Details of any required mitigation plans including identification of the affected parties responsible for mitigation.
   a. In-service date  
   b. Design information  
   c. Ratings of the facilities  
   d. A geographic map of the facility area  
   e. Electrical one-line diagrams of the facilities being connected.

9. Comments of affected parties covering agreement or points of disagreement of the proposed interconnection, if any.

10. Additional studies may be required for DC interconnections.

Compliance with the data provided submission requirements specified in this through this Addendum does not constitute approval of the physical interconnection of the facility by the Transmission Provider.

* * *

ATTACHMENT Y

I. OVERVIEW OF TRANSMISSION OWNER DESIGNATION PROCESS

1) The Transmission Provider shall designate a Transmission Owner in accordance with the process set forth in Section III of this Attachment Y for transmission facilities approved for construction by the SPP Board of Directors that meet all of the following criteria:

   a) Transmission facilities that are ITP Upgrades or high priority upgrades;

   b) Transmission facilities with a nominal operating voltage of 300-100 kV or
greater; and

c) Transmission facilities that are not a rebuild of an existing facility and do not use rights-of-way where facilities exist; and\[A6]\[4]—Transmission facilities located where the selection of a Transmission Owner pursuant to Section III of this Attachment Y does not violate relevant law where the transmission facility is to be built.\[A7]\[4]

2) For any upgrade meeting the specifications listed in Section I.1 of this Attachment Y, the Transmission Provider may, subject to approval by the SPP Board of Directors, designate the Transmission Owner(s) in accordance with Section IV of this Attachment Y if the following conditions are met: (i) the transmission facility is needed for the reliability of the grid; (ii) the transmission facility has a need date that cannot be met if the Transmission Owner Selection Process in Section III of this Attachment Y is followed; and (iii) no other transmission or non-transmission mitigation options are available to relieve the reliability issue to allow sufficient time for the Transmission Owner Selection Process to proceed.

3) For any upgrade not defined in Section I.1 of this Attachment Y, the Transmission Provider shall designate the Transmission Owner(s) in accordance with the process set forth in Section IV of this Attachment Y.

4) The designation from the Transmission Provider shall be provided pursuant to Section V of this Attachment Y.

5) The Transmission Provider shall track all projects that are approved for construction in accordance with Section VI of this Attachment Y.

III. TRANSMISSION OWNER SELECTION PROCESS FOR COMPETITIVE UPGRADES

1) Application and Qualification Process

b) Qualification Criteria

An Applicant must demonstrate that it meets the following qualification criteria:

iii) Managerial Criteria

An application must show that the Applicant has requisite expertise by describing its capability, experience, and process to address the following areas:
(1) Transmission Project Development

(a) engineering, permitting, environmental, equipment and material procurement, project management (including cost control, scope, and schedule management), construction, commissioning of new facilities, new or emerging technologies; and

(b) routing, surveying, rights-of-way, eminent domain, and real estate acquisition, including process for obtaining easements.

(2) Internal safety program, contractor safety program, safety performance record and program execution.

(3) Transmission Operations: control center operations, NERC compliance process and compliance history, registration or the ability to register for compliance with applicable NERC Reliability Standards, storm/outage response and restoration plan, record of past reliability performance, statement of which entity will be operating completed transmission facilities, staffing, equipment, and crew training.

(4) Transmission Maintenance: staffing and crew training, transmission facility and equipment maintenance, record of past maintenance performance, NERC compliance process and history, statement of which entity will be performing maintenance on completed transmission facilities.

(5) Ability to comply with Good Utility Practice, SPP Criteria, NERC Reliability Standards, and industry standards, and applicable local, state, and federal requirements.\(^{[A8]}\)

(6) Ability to comply with or demonstration of how the Applicant plans to be able to comply with NERC Reliability Standards.\(^{[A9]}\)

(67) Any other relevant project development experience that the Applicant believes may demonstrate its expertise in the above areas.

An Applicant can demonstrate that it meets the managerial criteria either on its own or by relying on an entity or entities with whom it has a corporate affiliation or contractual relationship (“Alternate Qualifying Entity (ies)”). If the Applicant seeks to satisfy the managerial criteria in whole or in part by relying on one or more Alternate Qualifying Entity(ies), the Applicant...
must submit: (1) materials demonstrating to the Transmission Provider’s satisfaction that the Alternate Qualifying Entity(ies) meet(s) the managerial criteria for which the Applicant is relying upon the Alternate Qualifying Entity(ies) to satisfy; and (2) an executed agreement that contractually obligates the Alternate Qualifying Entity(ies) to perform the function(s) for which the Applicant is relying upon the Alternate Qualifying Entity(ies) to satisfy.

2) Transmission Owner Selection Process

c) Request for Proposals

The Transmission Provider shall issue an RFP for each Competitive Upgrade, which shall contain information including, but not limited to:

i) An overview of the purpose for the RFP including the need for the Competitive Upgrade, regulatory context and authority, and other necessary information.

ii) A deadline for all RFP proposal submissions and minimum RFP proposal submission requirements.

iii) Minimum design specifications.

iv) The date regulatory approvals are required to be completed as determined by the Transmission Provider.

v) A requirement that the QRP provide the following information specific to the Competitive Upgrade for which it submits a proposal:

(1) financial information, including but not limited to demonstration of financing (including a reasonable contingency), detailed engineering and construction cost estimate, itemized revenue requirement calculations, and financial and business plans, including the nature of any FERC incentives the QRP intends to request;

(2) engineering information, including but not limited to engineering design of the project and technical requirements;

(3) construction information, including but not limited to anticipated project timeline including timeline for all necessary regulatory approvals, equipment acquisition, description of applicable rights-
of-way and real estate acquisition, description of routing, description of permitting, description of outage clearance(s), and identification of the party responsible for construction;

(4) operations and maintenance information, including but not limited to demonstration of operations, statement of which entity will be operating and maintaining the transmission facility, storm and outage response plan, maintenance plan, staffing, equipment, crew training, and record of past maintenance and outage restoration performance;

(5) safety information, including but not limited to identification of the internal safety program, contractor safety program, and safety performance record; and

(6) identification of information in the RFP proposal that the RFP respondent considers to be confidential.

vi) A requirement that the QRP demonstrate its financial strength by providing one of the following:

(1) demonstration that the QRP continues to satisfy the financial criteria set forth in Section III.1(b)(ii)(1) or (2) of this Attachment Y and that the Competitive Upgrade does not exceed 30% of the total capitalization of the QRP or its parent Guarantor;

(2) a performance bond from an insurance/surety company acceptable to the Transmission Provider in an amount equal to the total cost of the Competitive Upgrade, including financing costs, and a 30% contingency; or

(3) a letter of credit from a financial institution acceptable to the Transmission Provider in an amount equal to the total cost of the Competitive Upgrade, including financing costs, and a 30% contingency; or

(4) a demonstration that the QRP would otherwise be designated by the Transmission Provider as a DTO for the Competitive Upgrade pursuant to Section IV of this Attachment Y [A10].

vii) Information exchange requirements including but not limited to, identification of data required to be provided to the Transmission Provider in accordance with NERC reliability standards and CEII requirements.
viii) A description of the proposal evaluation procedure, including the statement of proposal evaluation methodology and criteria for acceptable proposals.

ix) A requirement that the QRP agrees to pay the RFP fee for each RFP proposal submitted, as outlined in Section III.2(e) of this Attachment Y, including the initial deposit at the time of submission of the RFP proposal.

x) A requirement that the QRP disclose any credit rating changes, bankruptcies, dissolutions, mergers, or acquisitions within the past five (5) years of the QTO or its parent, controlling shareholder, or entity providing a Guaranty pursuant to Section III.1(b)(ii)(2) of this Attachment Y.

VI. PROJECT TRACKING PROCESS

Costs and schedules related to all projects approved for construction under the Tariff shall be tracked by the Transmission Provider

1) Upon the acceptance of an NTC by a DTO, other than an NTC issued for refined cost estimation, the baseline cost of the project will be set. The baseline cost shall be the estimated cost of the project as agreed to between the DTO and the Transmission Provider at the time such NTC was accepted.

2) The DTO shall submit updates of the estimated costs and schedules to the Transmission Provider on at least a quarterly basis in a standard format and method defined by the Transmission Provider.

3) If at any time the cost projection significantly exceeds from the estimated baseline cost by more than a predetermined bandwidth defined by set forth in the Transmission Provider’s business practices[A11], the Transmission Provider shall investigate the reason for the change in cost and report to the SPP Board of Directors the reason for the change in cost and its recommendation on whether to accept the change in cost and reset the baseline cost. The SPP Board of Directors shall make the final determination as to the action that will be taken up to and including the cancellation of the project and withdrawal of the NTC.

4) If at any time the project schedule significantly changes, the Transmission Provider shall investigate the reason for the change and may take action in accordance with Section V.4 of this Attachment Y. [Factors that the Transmission Provider shall consider in determining whether a project schedule delay is significant shall include, but not be limited to, the need date, construction time, necessity for long-lead equipment, and permitting schedules][A12]
Proposed Market Protocol Language Revision (Redlined)
n/a

Proposed Business Practices Language Revision (Redlined)
n/a
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<td>On July 18, 2013, FERC issued its order addressing SPP’s compliance with the regional aspects of Order 1000. Sw. Power Pool, Inc., 144 FERC ¶ 61,059 (2013). This TRR address various requirements from the July 18 Order that include policy decisions by the SPC Task Force on Order No. 1000.</td>
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- Yes (Include a summary of impact and/or specific changes & BPR #)
- Yes (Include a summary of impact and/or specific changes)
- Yes (Include which corporate documents)
- Yes (Include a summary of impact and/or specific changes)
- Yes
Proposed Tariff Language Revisions (Redlined)

ATTACHMENT Y

I. OVERVIEW OF TRANSMISSION OWNER DESIGNATION PROCESS

1) The Transmission Provider shall designate a Transmission Owner in accordance with the process set forth in Section III of this Attachment Y for transmission facilities approved for construction or endorsed by the SPP Board of Directors for which the Transmission Provider issues a Notification to Construct after January 27, 2015 that meet all of the following criteria:

a) Transmission facilities that are ITP Upgrades or high priority upgrades;

b) Transmission facilities with a nominal operating voltage of 100 kV or greater;

c) Transmission facilities that are not a Rebuild of an existing facility;

d) Transmission projects that do not require both a Rebuild of existing facilities and new transmission facilities; and

e) Transmission facilities that are not a Local Transmission Facility.

2) For transmission projects involving both a Rebuild of existing facilities and the construction of new transmission facilities, the Transmission Provider shall designate the Transmission Owner(s) as follows:

a. If 80% or more of the total cost of the project consists of the Rebuild of existing facilities, then the Transmission Provider shall designate the Transmission Owner(s) for the project in accordance with Section IV of this Attachment Y; or

b. Otherwise, the Transmission Provider shall divide the project into two or more segments based upon whether that portion of the project is a Rebuild of existing facilities or new facilities. For those segments that are Rebuilds of existing facilities, the Transmission Provider shall designate the Transmission Owner(s) in accordance with Section IV of this Attachment Y. For those segments that are new facilities, the Transmission Provider shall designate the Transmission Owner(s) in accordance with Section III of this Attachment Y.

For any upgrade meeting the specifications listed in Section I.1 of this Attachment Y, the
Transmission Provider may, subject to approval by the SPP Board of Directors, designate the Transmission Owner(s) in accordance with Section IV of this Attachment Y if such upgrade is required to be in service within 3 years or less to address an identified reliability violation (“Short-Term Reliability Project”). To have a transmission project approved as a Short-Term Reliability Project, the Transmission Provider shall: (the following conditions are met: (i) the transmission facility is needed for the reliability of the grid; (ii) the transmission facility has a need date that cannot be met if the Transmission Owner Selection Process in Section III of this Attachment Y is followed; and (iii) no other transmission or non-transmission mitigation options are available to relieve the reliability issue to allow sufficient time for the Transmission Owner Selection Process to proceed.

a) Separately identify and post an explanation of the reliability violations and system conditions for which there is a time-sensitive need, in sufficient detail to allow stakeholders to understand the need and why it is time sensitive.

b) Provide to stakeholders and post on its website a full and supported written description explaining:
   i. The decision to designate the Transmission Owner pursuant to Section IV of this Attachment Y, including an explanation of other transmission or non-transmission options that the Transmission Provider considered but concluded would not sufficiently address the immediate reliability need; and
   ii. The circumstances that generated the immediate reliability need and an explanation of why that immediate reliability need was not identified earlier.

c) Permit stakeholders thirty (30) days to provide comments in response to the description required under Section I.3.b of this Attachment Y and make such comments publicly available.

d) Maintain and post a list of prior year designations of Short-Term Reliability Projects all transmission facilities for which the Transmission Provider designated the Transmission Owner pursuant to this Section I.3. The list must include the transmission facility’s Short-Term Reliability Project’s need date and the date that the DTO actually energized the project. Such list must be filed with the Commission as an informational filing in January of each calendar year covering the designations of the prior calendar year.

e) Obtain approval by the SPP Board of Directors.
44) For any upgrade not defined in Section I.1 or not meeting the requirements of Sections I.2 or I.3 of this Attachment Y, the Transmission Provider shall designate the Transmission Owner(s) in accordance with the process set forth in Section IV of this Attachment Y.

45) The designation from the Transmission Provider shall be provided pursuant to Section V of this Attachment Y.

56) The Transmission Provider shall track all projects that are approved for construction in accordance with Section VI of this Attachment Y.

II. DEFINITIONS

The terms used in this Attachment Y shall have the meanings as defined in this Section II or as otherwise defined in this Tariff.

Applicant: An entity that has submitted an application to the Transmission Provider to be a Qualified RFP Participant.

Competitive Upgrades: Those upgrades defined in Section I.1 of this Attachment Y or an upgrade for which the Transmission Provider must select a replacement Transmission Owner pursuant to Section IV.3 of this Attachment Y.

Guaranty: This term shall have the meaning given in Attachment X of this Tariff.

Guarantor: This term shall have the meaning given in Attachment X of this Tariff.

Industry Expert Panel: The panel of industry experts designated by the Oversight Committee to review and evaluate proposals submitted in response to any Request for Proposals in the Transmission Owner Selection Process.

Local Transmission Facility: A transmission facility that is located solely within a single Zone and has all of its costs allocated to such Zone.

Not-For-Profit: This term shall have the meaning given in Attachment X of this Tariff.

Qualified RFP Participant (“QRP”): An entity that has been determined by the Transmission Provider to satisfy the qualification criteria set forth in Section III.1 of this Attachment Y.

Rebuild: Shall mean, for purposes of this Attachment Y, a transmission facility that is an improvement to, addition to, or replacement of all or part of, an existing transmission facility.

Transmission Owner Selection Process: The process of determining the Transmission Owner
III. TRANSMISSION OWNER SELECTION PROCESS FOR COMPETITIVE UPGRADES

1) Application and Qualification Process
   
   a) Application

   Any entity that desires to participate in the Transmission Owner Selection Process outlined in this Section III must submit an application and supporting materials to demonstrate that it satisfies the qualification criteria set forth in this Section III. The Transmission Provider will evaluate the Applicant’s application and supporting materials to determine whether the Applicant satisfies the qualification criteria to be a QRP and participate in the Transmission Owner Selection Process in accordance with the timeline set out in Section III.1(c) of this Attachment Y.

   i) Any entity wishing to participate in the Transmission Owner Selection Process, whether a current Transmission Owner or another entity, must submit an application to the Transmission Provider in the form provided on the Transmission Provider’s website. The initial application must be received no later than June 30 of the year prior to the calendar year in which the Applicant wishes to begin participation in the Transmission Owner Selection Process. The Applicant shall submit an application fee with its application equal to the amount of the SPP annual membership fee. If the Applicant is a Member of SPP and is current in payment of its annual membership fee, then no application fee shall be required. The amount of the application fee shall be posted on the Transmission Provider’s website as part of the application form.

   ii) After the Transmission Provider determines that the entity is qualified to be a QRP, the entity shall remain a QRP for the five calendar years starting January 1 subsequent to that determination, subject to the annual certification process in Section III.1(d) of this Attachment Y and termination process set forth in Section III.1(e) of this Attachment Y. To be considered for continuation of QRP status for the subsequent five (5) year period, the QRP must submit a full application package in accordance with Section III.1(a)(i) of this Attachment Y by June 30 of the fifth year of the current period. The Transmission Provider shall evaluate the application in accordance with Section III.1(c) of this Attachment Y.

   iii) Any application from an Applicant will be posted on the Transmission
b) Qualification Criteria

An Applicant must demonstrate that it meets the following qualification criteria:

i) SPP Membership Criterion

An Applicant must be a Transmission Owner or be willing to sign the SPP Membership Agreement as a Transmission Owner if the Applicant is selected as part of the Transmission Owner Selection Process.

ii) Financial Criteria

An Applicant must demonstrate that it meets one of the following financial criteria:

(1) A senior unsecured investment grade rating or an issuer rating of BBB- or equivalent from a “nationally recognized statistical rating organization” as defined in Attachment X of this Tariff. If an Applicant maintains a rating from all three approved nationally recognized statistical rating organizations, it must maintain at least two ratings in the investment grade range. If an Applicant maintains a rating from two of the approved nationally recognized statistical rating organizations, it must maintain at least one of those ratings in the investment grade range.

(2) If the Applicant does not satisfy the requirement set forth in (1) above, the Applicant may submit to the Transmission Provider a Guaranty from its parent or affiliated organization that possesses an investment grade rating or an issuer rating of BBB- or equivalent from a “nationally recognized statistical rating organization” as defined in Attachment X of this Tariff. A Guaranty obligates the Guarantor to satisfy the obligations of the guarantee entity. Parent Guaranties are acceptable where the Applicant is a subsidiary, joint venture, or affiliate of the parent Guarantor. The Guaranty may be cancelled at any time that the Applicant establishes an investment grade rating as discussed in Section III.1(b)(ii)(1) of this Attachment Y. The Guaranty will be in a form consistent with Appendix D of Attachment X of this Tariff and must satisfy the following requirements:
(a) Be duly authorized by the Guarantor and signed by an officer of the Guarantor;

(b) State a minimum effective period of five (5) years, or provide for automatic renewal subject to cancellation with no less than sixty (60) days notice, provided that in all events the Guaranty is effective for all obligations of the Applicant undertaken prior to cancellation;

(c) Include a certification by the corporate secretary of the Guarantor that the execution, delivery, and performance of the Guaranty have been duly authorized;

(d) Certify that the Guaranty does not violate other undertakings or requirements applicable to the Guarantor and is enforceable against the Guarantor in accordance with its terms;

(e) Obligate the guarantor to submit a representation letter annually indicating any material changes from the information provided in the Applicant’s application related to the Guarantor and Guaranty, and representing that the Guarantor continues to satisfy the financial criteria;

(f) Secure all obligations of the Applicant under or in connection with this Tariff and other agreements with the Transmission Provider;

(g) Be supported by adequate consideration and be otherwise binding as a matter of law; and

(h) Include as an attachment a resolution of the board of directors or other governing body of the Guarantor authorizing the Guaranty.

(3) If the Applicant does not satisfy the requirements set forth in (1) or (2) above, the Applicant may submit to the Transmission Provider a formal letter of reference from a commercial bank evidencing an existing line of credit from commercial banks (or access to an existing line of credit through Inter-company agreements with a
Parent or Affiliate), or bonding indication letter from an insurance or surety company either of which indicate a willingness to extend credit to the Applicant in an amount of at least $25,000,000 (for bank) or willingness to provide a surety bond in the amount of at least $25,000,000 (for an insurance or surety company). Commercial bank reference letters acceptable to the Transmission Provider must be issued by a financial institution organized under the laws of the United States or any state of the United States or the District of Columbia or a branch or agency of a foreign commercial bank located in the United States, with a minimum corporate debt rating of A- or equivalent from a “nationally recognized statistical rating organization” as defined in Attachment X of this Tariff and total assets of at least $10 billion. Bonding indication letters acceptable to the Transmission Provider must be issued by an insurance or surety company with a minimum financial strength rating of A- and a minimum financial size category of X from the A.M. Best Company.

(4) If the Applicant is a municipality, a cooperative, or other Not-For-Profit entity, the Applicant may satisfy the financial criteria requirement by providing evidence of direct rate-setting authority or taxing authority. The Applicant must possess this authority and cannot rely on an affiliation with another entity that possesses rate-setting or taxing authority.

iii) Managerial Criteria

An application must show that the Applicant has requisite expertise by describing its capability, experience, and process to address the following areas:

(1) Transmission Project Development

(a) engineering, permitting, environmental, equipment and material procurement, project management (including cost control, scope, and schedule management), construction, commissioning of new facilities, new or emerging technologies; and

(b) routing, surveying, rights-of-way, eminent domain, and real estate acquisition, including process for obtaining easements.

(2) Internal safety program, contractor safety program, safety
performance record and program execution.

(3) Transmission Operations: control center operations, NERC compliance process and compliance history, registration or the ability to register for compliance with applicable NERC Reliability Standards, storm/outage response and restoration plan, record of past reliability performance, statement of which entity will be operating completed transmission facilities, staffing, equipment, and crew training.

(4) Transmission Maintenance: staffing and crew training, transmission facility and equipment maintenance, record of past maintenance performance, NERC compliance process and history, statement of which entity will be performing maintenance on completed transmission facilities.

(5) Ability to comply with Good Utility Practice, SPP Criteria, and industry standards.

(6) Ability to comply with or demonstration of how the Applicant plans to be able to comply with NERC Reliability Standards.

(7) Any other relevant project development experience that the Applicant believes may demonstrate its expertise in the above areas.

Applicant can demonstrate that it meets the managerial criteria either on its own or by relying on one or more an entity or entities with whom it has a corporate affiliation or contractual relationship that satisfy any of the managerial criteria for which the Applicant seeks to rely upon such entity(ies) to satisfy (“Alternate Qualifying Entity (ies)”). If the Applicant seeks to satisfy the managerial criteria in whole or in part by relying on one or more Alternate Qualifying Entity(ies), the Applicant must submit—(1) materials demonstrating to the Transmission Provider’s satisfaction that the Alternate Qualifying Entity(ies) meet(s) the managerial criteria for which the Applicant is relying upon the Alternate Qualifying Entity(ies) to satisfy; and (2) either (i) an executed agreement that contractually obligates the Alternate Qualifying Entity(ies) to perform the function(s) for which the Applicant is relying upon the Alternate Qualifying Entity(ies) to satisfy.

c) Determination of Qualifications

i) Upon receiving an application, the Transmission Provider shall review the
application to determine whether the Applicant satisfies the qualification criteria set forth in Section III 1(b) of this Attachment Y. The Transmission Provider shall notify each Applicant of its determination no later than September 30 of the year in which the application was submitted.

ii) If the Transmission Provider determines that the Applicant fails to satisfy one or more of the qualification criteria, the Transmission Provider shall inform the Applicant of such deficiency(ies), and the Applicant shall be allowed to cure any deficiency(ies) within thirty (30) calendar days of notice from the Transmission Provider by providing any additional information that the Applicant believes cures the deficiency(ies). The Transmission Provider shall review the information provided by the Applicant and render a final determination of whether the Applicant satisfies the qualification criteria within forty-five (45) calendar days of the Transmission Provider’s receipt of the additional information. If, after attempting to cure the deficiency(ies), the Applicant still has not satisfied the qualification criteria, the Applicant shall be disqualified from the Transmission Owner Selection Process for the following year.

iii) Upon the Transmission Provider’s determination that an Applicant satisfies the qualification criteria, the Transmission Provider shall notify the Applicant that it has been determined to be a QRP and can participate in the Transmission Owner Selection Process effective January 1 of the following calendar year. By December 31 of each year, the Transmission Provider shall post on its website a list of all QRPs that are eligible to participate in the following calendar year for any Competitive Upgrade.

d) Annual Recertification Process and Reporting Requirements

i) By June 30 of each year, each QRP must submit to the Transmission Provider a notarized letter signed by an authorized officer of the QRP certifying that the QRP continues to meet the current qualification criteria or indicating any material changes to the information provided in its application. The QRP shall pay an annual certification fee equal to the amount of the SPP annual membership fee. If the QRP is a Member of SPP and is current in payment of its annual membership fee, then no certification fee will be required.

ii) If at any time there is a change to the information provided in its application, a QRP shall be required to inform the Transmission Provider within seven (7) calendar days of such change so that the Transmission Provider may determine whether the QRP continues to satisfy the
qualification criteria. Upon notification of any such change, the Transmission Provider shall have the option to: (a) determine that the change does not affect the QRP’s status; (b) suspend the QRP’s eligibility to participate in the Transmission Owner Selection Process until the QRP has cured any deficiency in its qualifications to the Transmission Provider’s satisfaction; (c) allow the QRP to continue to participate in the Transmission Owner Selection Process for a limited time period, as specified by the Transmission Provider, while the QRP cures the deficiency to the Transmission Provider’s satisfaction; or (d) terminate the QRP status in accordance with Section III.1(e) of this Attachment Y.

e) Termination of QRP Status

The Transmission Provider may terminate a QRP’s status if the QRP: (1) fails to submit its annual certification letter; (2) fails to pay the applicable fee as required by Section III.1(d) of this Attachment Y; (3) experiences a change in its qualifications and the Transmission Provider determines that it may no longer be a QRP; or (4) informs the Transmission Provider that it no longer desires to be a QRP; or (5) fails to notify the Transmission Provider of a change to the information provided in its application in accordance with Section III.1(d) of this Attachment Y.

f) Dispute Resolution

If the Applicant or QRP (“Affected Party”) disagrees with the Transmission Provider’s determination regarding its qualifications under Section III.1 of this Attachment Y, the Affected Party may initiate dispute resolution procedures. Any such dispute shall first be referred to a designated senior representative of the Transmission Provider and a senior representative of the Affected Party for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) calendar days (or such other period upon which the Transmission Provider and the Affected Party may agree) by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth in Sections 12.2 through 12.5 of this Tariff.

2) Transmission Owner Selection Process

a) Overview

Once a Competitive Upgrade has been approved by the SPP Board of Directors, the Transmission Provider shall issue a Request for Proposals (“RFP”) for the
Competitive Upgrade as specified in this Section III of Attachment Y.

b) Industry Expert Panel

i) On an annual basis, the Oversight Committee or its successor shall identify a pool of candidates to serve as industry experts on one or more Industry Expert Panel(s) (“IEP”) to evaluate proposals that are submitted in response to any RFP issued by the Transmission Provider pursuant to this Section III of Attachment Y. IEP candidates shall have documented expertise on file with the Transmission Provider in one or more of the following areas: (1) electric transmission engineering design; (2) electric transmission project management and construction; (3) electric transmission operations; (4) electric transmission rate design and analysis; and (5) electric transmission finance.

ii) Each industry expert must disclose to the Oversight Committee any affiliation with any SPP stakeholder or any QRP. In the event an affiliation exists, the Oversight Committee will evaluate whether the affiliation may adversely impact an industry expert’s ability to independently evaluate RFP proposals, and the Oversight Committee may disqualify that industry expert.

iii) The Oversight Committee shall present its recommended pool of IEP candidates to the SPP Board of Directors for approval. The name and qualifications of each recommended candidate shall be posted on the Transmission Provider’s website prior to SPP Board of Directors approval. Approval of the IEP candidate pool shall be made prior to the meeting in which a Competitive Upgrade is to be approved.

iv) The Oversight Committee shall create an IEP from the IEP candidate pool to evaluate proposals resulting from the RFPs. The IEP shall consist of three (3) to five (5) industry experts such that the IEP will have expertise in all five (5) areas listed in Section III.2 (b) (i) of this Attachment Y. Upon SPP Board of Directors approval, the Oversight Committee may create additional IEPs. Each IEP member must sign a confidentiality agreement prior to participating in the Transmission Owner Selection Process.

v) If a member of a designated IEP becomes affiliated with a stakeholder or QRP, the IEP member shall immediately notify the Transmission Provider and the Oversight Committee. The Oversight Committee shall evaluate whether any affiliation between a member of a designated IEP and a stakeholder or QRP may adversely impact the IEP member’s ability to independently evaluate RFP proposals reviewed by that IEP. In such event,
the Oversight Committee may remove the IEP member from that IEP. If necessary, the Oversight Committee may designate a replacement IEP member from the IEP candidate pool.

vi) The Transmission Provider shall facilitate the IEP’s efforts to develop recommendations to the SPP Board of Directors. The IEP will evaluate all aspects of each proposal submitted for its review. Once all evaluations are complete, the IEP will develop a single recommendation for the SPP Board of Directors consisting of its recommended RFP proposal and an alternate RFP proposal for each Competitive Upgrade.

c) Request for Proposals

The Transmission Provider shall issue an RFP for each Competitive Upgrade, which shall contain information including, but not limited to:

i) An overview of the purpose for the RFP including the need for the Competitive Upgrade, regulatory context and authority, and other necessary information.

ii) A deadline for all RFP proposal submissions and minimum RFP proposal submission requirements.

iii) Minimum design specifications.

iv) The date regulatory approvals are required to be completed as determined by the Transmission Provider.

v) A requirement that the QRP provide the following information specific to the Competitive Upgrade for which it submits a proposal:

1) financial information, including but not limited to demonstration of financing (including a reasonable contingency), detailed engineering and construction cost estimate, itemized revenue requirement calculations, and financial and business plans, including the nature of any FERC incentives the QRP intends to request;

2) engineering information, including but not limited to engineering design of the project and technical requirements;

3) construction information, including but not limited to anticipated project timeline including timeline for all necessary regulatory approvals, equipment acquisition, description of applicable rights-
of-way and real estate acquisition, description of routing, description of permitting, description of outage clearance(s), and identification of the party responsible for construction;

(4) operations and maintenance information, including but not limited to demonstration of operations, statement of which entity will be operating and maintaining the transmission facility, storm and outage response plan, maintenance plan, staffing, equipment, crew training, and record of past maintenance and outage restoration performance;

(5) safety information, including but not limited to identification of the internal safety program, contractor safety program, and safety performance record; and

(6) identification of information in the RFP proposal that the RFP respondent considers to be confidential.

vi) A requirement that the QRP demonstrate its financial strength by providing one of the following:

(1) demonstration that the QRP continues to satisfy the financial criteria set forth in Section III.1(b)(ii)(1) or (2) of this Attachment Y and that the Competitive Upgrade does not exceed 30% of the total capitalization of the QRP or its parent Guarantor;

(2) a performance bond from an insurance/surety company acceptable to the Transmission Provider in an amount equal to the total cost of the Competitive Upgrade, including financing costs, and a 30% contingency; or

(3) a letter of credit from a financial institution acceptable to the Transmission Provider in an amount equal to the total cost of the Competitive Upgrade, including financing costs, and a 30% contingency.

vii) Information exchange requirements including but not limited to, identification of data required to be provided to the Transmission Provider in accordance with NERC reliability standards and CEII requirements.

viii) A description of the proposal evaluation procedure, including the statement of proposal evaluation methodology and criteria for acceptable proposals.
ix) A requirement that the QRP agrees to pay, as outlined in Section III.2(e) of this Attachment Y: (1) a deposit for each RFP proposal submitted, for its share of the Transmission Provider’s costs to administer the RFP fee Transmission Owner Selection Process for each RFP proposal submitted, as outlined in Section III.2(e) of this Attachment Y; and (2) including the initial Transmission Owner Selection Process deposit at the time of submission of the RFP proposal and any additional costs that are assessed after the completion of the Transmission Owner Selection Process, and calculation of the total cost of administering the Transmission Owner Selection Process.

x) A requirement that the QRP disclose any credit rating changes, bankruptcies, dissolutions, mergers, or acquisitions within the past five (5) years of the QTO or its parent, controlling shareholder, or entity providing a Guaranty pursuant to Section III.1(b)(ii)(2) of this Attachment Y.

xi) A requirement that the QRP provide its Internal Revenue Service Tax Identification Number.

d) RFP Process and Timeline

i) The Transmission Provider shall issue each RFP by or before the later of: (1) seven (7) calendar days after approval of the Competitive Upgrade by the SPP Board of Directors; or (2) eighteen (18) months prior to the date that anticipated financial expenditure is needed for a Competitive Upgrade. The RFP shall be issued only to QRPs.

ii) Each RFP respondent shall submit a complete proposal in response to the RFP within ninety (90) calendar days from the date the RFP is issued (“RFP Response Window”).

iii) The Transmission Provider shall not disclose any information contained in any RFP proposal, except to the IEP, until the issuance of the IEP reports in accordance with Section III.2(d)(vi)(2) of this Attachment Y.

iv) Upon receipt of an RFP proposal, the Transmission Provider shall immediately review the proposal for completeness, and shall promptly notify the RFP respondent if its proposal is incomplete. The RFP respondent may submit information in order to complete the proposal if such submittal is made within the RFP Response Window. Any RFP respondent that fails to submit a complete proposal within the RFP Response Window will be deemed to have waived its right to respond to the RFP.
v) If the Transmission Provider does not receive any complete proposals in response to an RFP, the Transmission Provider shall inform the SPP Board of Directors and shall select the DTO in accordance with the process set forth in Section IV of this Attachment Y.

vi) Upon the closing of the RFP Response Window, the Transmission Provider shall provide the RFP proposals to the IEP. The IEP shall review, score, and rank all RFP proposals and submit its recommendation to the SPP Board of Directors based upon selection criteria outlined in Section III.2(f) of this Attachment Y. The identity of RFP respondents that submitted the RFP proposals shall not be disclosed to the SPP Board of Directors as part of the IEP’s recommendation. The IEP’s recommendation shall be submitted to the SPP Board of Directors within sixty (60) calendar days of the initiation of the IEP’s review (“Review Period”). Upon IEP request, the Oversight Committee may extend the Review Period an additional thirty (30) calendar days. Notification of such extension shall be provided to the SPP Board of Directors and posted on the Transmission Provider’s website.

(1) During its review, the IEP may initiate communication with RFP respondents to obtain answers to any additional questions about proposals, and any such communications shall be documented by the IEP. Lobbying of the IEP by, or on behalf of, any RFP respondent is prohibited, and may result in disqualification of the RFP respondent by the Transmission Provider from the RFP process. The IEP shall score and rank each RFP proposal in a non-discriminatory manner based upon the information supplied in the RFP proposal or obtained during the Review Period.

(2) The IEP shall compile an internal report for the Transmission Provider detailing the process, data, results of its deliberations, and its recommended RFP proposal and an alternate RFP proposal for each Competitive Upgrade. The Transmission Provider shall be responsible for producing two redacted versions of the internal report, a Board of Directors report and a public report. The Board of Directors report shall exclude the names of the RFP respondents. The public report shall exclude the names of RFP respondents and any confidential information obtained during the Transmission Owner Selection Process. No later than fourteen (14) calendar days prior to the SPP Board of Directors meeting during which the SPP Board of Directors will consider the IEP recommendation, the public report shall be posted on the Transmission Provider’s website and the Board of Directors report shall be provided to the SPP Board.
vii) Except as provided in Sections III.2(d)(vii)(a) and III.2(d)(vii)(b) of this Attachment Y, the SPP Board of Directors shall select an RFP proposal ("Selected RFP Proposal") and an alternate RFP proposal for each Competitive Upgrade based primarily on the information provided by the IEP. The Transmission Provider shall notify the RFP respondent that submitted the Selected RFP Proposal that it has been chosen by the SPP Board of Directors to become the DTO for the Competitive Upgrade ("Selected RFP Respondent") and the Transmission Provider shall issue an NTC for the Competitive Upgrade pursuant to Section V of this Attachment Y. To become the DTO for the Competitive Upgrade, the Selected RFP Respondent must, within seven (7) calendar days of receiving such notice: (1) sign any necessary agreement(s) to assume all of the responsibilities of a Transmission Owner related to the Competitive Upgrade pursuant to the SPP Membership Agreement and this Tariff; (2) submit to the Transmission Provider a deposit in accordance with Section III.2(d)(xii) of this Attachment Y; and (3) provide written notification to the Transmission Provider that it accepts the NTC.

a. If the Board of Directors accepts the IEP’s recommendation, pursuant to Section III.2(f)(i) of this Attachment Y, resulting in all RFP proposals being eliminated from consideration due to a low score in any evaluation category, the DTO for the Competitive Upgrade will be identified as follows:

1. If the Competitive Upgrade qualifies under Section I.3 of this Attachment Y, the DTO will be identified as set forth in Section I.3 of this Attachment Y.

2. If the Competitive Upgrade does not meet the conditions set forth in Section III.2(d)(vii)(a)(1) of this Attachment Y, the Transmission Provider shall reevaluate the Competitive Upgrade to determine what action to take, including: (a) resubmission of the Competitive Upgrade for DTO selection under Section III of this Attachment Y; (b) modification of the Competitive Upgrade and resubmission of the Competitive Upgrade for DTO selection under Section III of this Attachment Y; or (c) cancellation of the Competitive Upgrade.

b. If a Competitive Upgrade was previously resubmitted, pursuant to Section III.2(d)(vii)(a) of this Attachment Y, for selection of a DTO...
viii) The Selected RFP Respondent shall be deemed to have waived its right to become the DTO if, within seven (7) calendar days of receiving such notice, the Selected RFP Respondent: (1) does not respond to such notice from the Transmission Provider; (2) notifies the Transmission Provider that it is no longer willing to become the Transmission Owner for the Competitive Upgrade; (3) fails to sign the necessary agreement(s); (4) fails to provide a deposit in accordance with Section III.2(d)(xii) of this Attachment Y; or (5) fails to provide written notification to the Transmission Provider that it accepts the NTC. In such circumstances, the Transmission Provider shall notify the SPP Board of Directors.

ix) If the Selected RFP Respondent has waived its right to become the DTO pursuant to Section III.2(d)(viii) of this Attachment Y, the Transmission Provider shall notify the RFP respondent that submitted the alternate RFP proposal that it has been chosen by the SPP Board of Directors to become the DTO for the Competitive Upgrade, and the Transmission Provider shall issue an NTC for the Competitive Upgrade pursuant to Section V of this Attachment Y. To become the DTO for the Competitive Upgrade, the RFP respondent that submitted the alternate RFP proposal must, within seven (7) calendar days of receiving such notice: (1) sign any necessary agreement(s) to assume all of the responsibilities of a Transmission Owner related to the Competitive Upgrade pursuant to the SPP Membership Agreement and this Tariff; (2) submit to the Transmission Provider a deposit in accordance with Section III.2(d)(xii) of this Attachment Y; and (3) provide written notification to the Transmission Provider that it accepts the NTC.

x) The RFP respondent that submitted the alternate RFP proposal shall be deemed to have waived its right to become the DTO if, within seven (7) calendar days of receiving such notice, the RFP respondent that submitted the alternate RFP proposal: (1) does not respond to such notice from the Transmission Provider; (2) notifies the Transmission Provider that it is no longer willing to become the Transmission Owner for the Competitive Upgrade; (3) fails to sign the necessary agreement(s); (4) fails to provide a deposit in accordance with Section III.2(d)(xii) of this Attachment Y; or (5) fails to provide written notification to the Transmission Provider that it accepts the NTC. In such circumstances, the Transmission Provider shall notify the SPP Board of Directors, and the Transmission Provider shall determine the DTO in accordance with the process set forth in Section IV of this Attachment Y.
xi) The DTO for a Competitive Upgrade cannot assign the Competitive Upgrade to another entity.

xii) When accepting the responsibilities of being a DTO for a Competitive Upgrade, the Selected RFP respondent shall provide the following to the Transmission Provider:

   (1) a cash deposit representing 2% of the estimated cost of the Selected RFP Proposal; and

   (2) a firm capital commitment acceptable to the Transmission Provider that is sufficient to complete the Competitive Upgrade, including one of the following:

       a. A binding commitment letter from lenders and/or equity providers;

       b. Cash held in escrow;

       c. A performance and payment bond;

       d. or surety bond;

       de. Existing balance sheet liquidity; or

       ef. Demonstrated history of ability to obtain adequate capital to support the project.

The cash deposit shall be held in escrow by the Transmission Provider. Upon reaching the 50% completion milestone of the Competitive Upgrade, as determined by the Transmission Provider, the Transmission Provider shall refund the deposit, plus any interest the deposit accrued while in escrow, to the DTO. If the DTO fails to reach the 50% completion milestone of the Competitive Upgrade in accordance with Section III.2(g) of this Attachment Y, then the DTO shall forfeit the deposit and any accrued interest. The Transmission Provider shall then select a new DTO in accordance with Section III.2(g) and apply the deposit and accrued interest to reduce the final cost of the Competitive Upgrade. If the Transmission Provider cancels the Competitive Upgrade through no fault of the DTO, then the Transmission Provider shall refund the deposit and accrued interest.
e) **RFP Fee Transmission Owner Selection Process Deposit and Cost Calculation**

Each RFP proposal shall pay its share of the Transmission Provider’s costs incurred to administer the Transmission Owner Selection RFP Process for each Competitive Upgrade, as calculated pursuant to this Section III.2(e). Initially, at the time of submission of each RFP proposal, each RFP respondent shall submit a Transmission Owner Selection Process deposit of $510,000 with for each proposal, which shall be equal to the Transmission Provider’s estimate of the fee for participation in the RFP process. The Transmission Provider shall hold each RFP respondent’s Transmission Owner Selection Process deposit in a segregated interest bearing account in the name of the RFP respondent tied to the RFP respondent’s Internal Revenue Service Tax Identification Number.

The actual RFP Transmission Owner Selection Process costs will be determined at the completion of the process, and all RFP respondents will make additional payments or obtain refunds based on the reconciliation of Transmission Owner Selection Process deposits collected and actual RFP Transmission Owner Selection Process costs. The Transmission Owner Selection Process costs shall include the Transmission Provider’s staff and administrative costs associated with administering the Transmission Owner Selection Process for the Competitive Upgrade and all costs associated with administering the IEP process for the Competitive Upgrade, including the identification, recruiting, hiring, and retention of industry experts to serve on the IEP(s). The costs shall be allocated to each RFP proposal on a pro-rata share basis, calculated by taking the total RFP Transmission Owner Selection Process costs for each Competitive Upgrade and dividing by the number of proposals submitted for that Competitive Upgrade. The Transmission Provider shall refund any unused deposit amounts with interest earned on such deposits.

f) **Transmission Owner Selection Criteria and Scoring**

i) The IEP will develop a final score for each RFP proposal and provide its recommended RFP proposal and an alternate RFP proposal to the SPP Board of Directors for each Competitive Upgrade. The IEP evaluation and recommendation shall not be administered in an unduly discriminatory manner. The RFP proposal with the highest total score may not always be recommended. The IEP may recommend that any RFP proposal be
eliminated from consideration due to a low score in any individual evaluation category.

ii) The IEP may award up to one thousand (1000) base points for each RFP proposal. Additional details on each evaluation category are provided in the Transmission Provider’s business practices. An additional one hundred (100) points shall be available to provide an incentive for stakeholders to share their ideas and expertise to promote innovation and creativity in the transmission planning process.

iii) **Base Points:** The evaluation categories and maximum base points for each category are listed below.

1. **Engineering Design (Reliability/Quality/General Design), 200 points:** Measures the quality of the design, material, technology, and life expectancy of the Competitive Upgrade. Criteria considered in this evaluation category shall include, but not be limited to:

   a. Type of construction (wood, steel, design loading, etc.);
   b. Losses (design efficiency);
   c. Estimated life of construction; and
   d. Reliability/quality metrics.

2. **Project Management (Construction Project Management), 200 points:** Measures an RFP respondent’s expertise in implementing construction projects similar in scope to the Competitive Upgrade that is the subject of the RFP. Criteria considered in this evaluation category shall include, but not be limited to:

   a. Environmental;
   b. Rights-of-way ownership, control, or acquisition;
   c. Procurement;
   d. Project scope;
   e. Project development schedule (including obtaining necessary regulatory approvals);
   f. Construction;
   g. Commissioning;
   h. Timeframe to construct; and
   i. [BF14] RPFFP respondent’s plan to obtain authorization to construct transmission facilities in the state(s) in which the Competitive Upgrade will be located;
(j) RFP respondent has a right of first refusal granted under relevant law for the Competitive Upgrade; and

(i) Experience/track record.

(3) Operations (Operations/Maintenance/Safety), 250 points: Measures safety and capability of an RFP respondent to operate, maintain, and restore a transmission facility. Criteria considered in this evaluation category shall include, but not be limited to:

(a) Control center operations (staffing, etc.);
(b) Storm/outage response plan;
(c) Reliability metrics;
(d) Restoration experience/performance;
(e) Maintenance staffing/training;
(f) Maintenance plans;
(g) Equipment;
(h) Maintenance performance/expertise;
(i) NERC compliance-process/history;
(j) Internal safety program;
(k) Contractor safety program; and
(l) Safety performance record (program execution).

(4) Rate Analysis (Cost to Customer), 225 points: Measures an RFP respondent’s cost to construct, own, operate, and maintain the Competitive Upgrade over a forty (40) year period. Criteria considered in this evaluation category shall include, but not be limited to:

(a) Estimated total cost of project;
(b) Financing costs;
(c) FERC incentives;
(d) Revenue requirements;
(e) Lifetime cost of the project to customers;
(f) Return on equity;

Material on hand, assets on hand, or rights-of-way ownership, control, or acquisition, or approval, assets on hand; and

(h) Cost certainty guarantee.

(5) Finance (Financial Viability and Creditworthiness), 125 points: Measures an RFP respondent’s ability to obtain financing for the Competitive Upgrade. Criteria considered in this evaluation category shall include, but not be limited to:
(a) Evidence of financing;
(b) Material conditions;
(c) Financial/business plan;
(d) Pro forma financial statements;
(e) Expected financial leverage;
(f) Debt covenants;
(g) Projected liquidity;
(h) Dividend policy; and
(i) Cash flow analysis

iv) **Incentive Points:** Each RFP respondent that submitted a detailed project proposal (“DPP”) in accordance with Attachment O Section III. 8(b) of this Tariff that was selected and approved for construction as a Competitive Upgrade shall receive one hundred (100) incentive points in the Transmission Owner Selection Process for that Competitive Upgrade, which shall be added to the total base points awarded by the IEP. To demonstrate eligibility for the incentive points, the RFP respondent must document in its RFP response that it submitted a DPP for that Competitive Upgrade. The eligibility for the incentive points may only be awarded to the RFP respondent if the DPP was submitted during the ITP assessment from which the Competitive Upgrade was approved. The Transmission Provider shall confirm such eligibility in accordance with Attachment O Section III.8(b) of this Tariff and inform the IEP.

g) **Failure of a Transmission Owner to Complete the Competitive Upgrade**

If, after accepting the NTC, the DTO cannot or is unwilling to complete the Competitive Upgrade as directed by the Transmission Provider, the Transmission Provider shall evaluate the status of the Competitive Upgrade and may designate a new DTO for the Competitive Upgrade in accordance with Section V.4 of this Attachment Y. If the Transmission Provider has determined that there is sufficient time for the Transmission Owner Selection Process to be completed and the Competitive Upgrade placed in service prior to the required need date as determined by the Transmission Provider, the process described in Section III of this Attachment Y shall be used to designate another entity to become the DTO for the Competitive Upgrade. If sufficient time is not available, the Transmission Provider shall designate a new DTO for the Competitive Upgrade in accordance with Section IV of this Attachment Y.
ATTACHMENT O
TRANSMISSION PLANNING PROCESS

III. The Integrated Transmission Planning Process

The ITP process is an iterative three-year process that includes 20-Year, 10-Year and Near Term Assessments. The 20-Year Assessment identifies the transmission projects, generally above 300 kV, and provides a grid flexible enough to provide benefits to the region across multiple scenarios. The 10-Year Assessment focuses on facilities 100 kV and above to meet the system needs over a ten-year horizon. The Near Term Assessment is performed annually and assesses the system upgrades, at all applicable voltage levels, required in the near term planning horizon.

1) Commencement of the Process

At the beginning of each calendar year the Transmission Provider shall notify stakeholders as to which part(s) of the integrated transmission planning cycle will take place during that year and the approximate timing of activities required to develop the SPP Transmission Expansion Plan. Notice of commencement of the process shall be posted on the SPP website and distributed via email distribution lists. Such notice shall include a timeline indicating when stakeholders are able to submit transmission needs, including transmission needs driven by Public Policy Requirements, and solutions to such needs as described in this Section III.

2) Transmission Planning Forums

The transmission planning forums include planning summits and sub-regional planning meetings and these are conducted as follows:

a) Planning Summits

i) The purpose of the planning summits is for the Transmission Provider and the stakeholders to share current SPP transmission network issues, develop the study scopes, provide solution alternatives and review study findings. These summits also provide an open forum where all stakeholders have an opportunity to provide advice and recommendations to the Transmission Provider to aid in the development of the SPP Transmission Expansion Plan.
### ii) The planning summits shall be open to all entities.

### iii) The Transmission Provider shall chair and facilitate the planning summits.

### iv) Planning summits shall be held at least semi-annually, including sub-regional breakout sessions of the SPP Region. Teleconference capability will be made available for planning summits. Planning summit web conferences shall be held as needed.

### v) Notice of the planning summits and web conferences shall be posted on the SPP website and distributed via email distribution lists.

#### b) Sub-regional Planning Meetings

- **i)** The Transmission Provider shall define sub-regions from time to time to address local area planning issues.

- **ii)** The purpose of the sub-regional planning meetings is to identify unresolved local stakeholder issues and transmission solutions at a more granular level. The sub-regional planning meetings shall provide stakeholders with local needs the opportunity to provide advice and recommendations to the Transmission Provider and to the Transmission Owners. The sub-regional planning meetings shall provide a forum to review local planning criteria and needs as specified in Section II of this Attachment O.

- **iii)** The sub-regional planning meetings shall be open to all entities.

- **iv)** The Transmission Provider shall facilitate the sub-regional planning meetings.

- **v)** A planning meeting shall be held at least annually for each individual sub-region.

- **vi)** The sub-regional planning meetings shall be held in conjunction with the stakeholder working group meetings. Teleconference capability will be made available for sub-regional planning meetings. Sub-regional planning web conferences shall be held as needed.

- **vii)** Notice of the sub-regional planning meetings, teleconferences and web conferences shall be posted on the SPP website and distributed via email distribution lists.
3) Preparation of the 20-Year Assessment

a) The Transmission Provider shall perform a 20-Year Assessment once every three years. The timing of this assessment shall generally be in the first half of each three-year cycle.

b) The 20-Year Assessment shall review the system for a twenty-year planning horizon and address, at a minimum, facilities 300 kV and above needed in year 20. This assessment is not intended to review each consecutive year in the planning horizon. The Transmission Provider shall work with stakeholders to identify the appropriate year(s) to study in developing the assessment study scope.

c) The 20-Year Assessment shall assess the cost effectiveness of proposed solutions over a forty-year time horizon.

d) The Transmission Provider shall develop the assessment study scope with input from the stakeholders. The study scope shall take into consideration the input requirements described in Section III.6.

e) The assessment study scope shall specify the methodology, criteria, assumptions, and data to be used.

[BF17] The Transmission Provider, in consultation with the stakeholder working groups, shall finalize the assessment study scope including the identification of those transmission needs that will be studied, such as transmission needs driven by Public Policy Requirements, as further described in the Integrated Transmission Planning Manual.

g) The assessment study scope shall be posted on the SPP website and will be included in the published annual SPP Transmission Expansion Plan report. The assessment study scope shall include an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local and regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated.

h) In accordance with the assessment study scope, the Transmission Provider shall analyze potential solutions following the process set forth in Section III.8.

4) Preparation of the 10-Year Assessment

a) The Transmission Provider shall perform a 10-Year Assessment once every three years as part of the three year planning cycle. The timing of this assessment shall generally be in the second half of the three-year planning cycle.
b) The 10-Year Assessment shall review the system for a ten-year planning horizon and address, at a minimum, facilities 100 kV and above needed in year 10. This assessment is not intended to review each consecutive year in the planning horizon. The Transmission Provider shall work with stakeholders to identify the appropriate year(s) to study in developing the assessment study scope.

c) The 10-Year Assessment shall assess the cost effectiveness of proposed solutions over a forty-year time horizon.

d) The Transmission Provider shall develop the assessment study scope with input from the stakeholders. The study scope shall take into consideration the input requirements described in Section III.6.

e) The assessment study scope shall specify the methodology, criteria, assumptions, and data to be used.

f) The Transmission Provider, in consultation with the stakeholder working groups, shall finalize the assessment study scope, including the identification of those transmission needs that will be studied, such as transmission needs driven by Public Policy Requirements, as further described in the Integrated Transmission Planning Manual.

g) The assessment study scope shall be posted on the SPP website and will be included in the published annual SPP Transmission Expansion Plan report. The assessment study scope shall include an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local and regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated.

h) In accordance with the assessment study scope, the Transmission Provider shall analyze potential solutions, including those upgrades approved by the SPP Board of Directors from the most recent 20-Year Assessment, following the process set forth in Section III.8.

5) Preparation of the Near Term Assessment

a) The Transmission Provider shall perform the Near Term Assessment on an annual basis.

b) The Near Term Assessment will be performed on a shorter planning horizon than the 10-Year Assessment and shall focus primarily on identifying solutions required to meet the reliability criteria defined in Section III.6.
c) The assessment study scope shall specify the methodology, criteria, assumptions, and data to be used to develop the list of proposed near term upgrades.

d) The Transmission Provider, in consultation with the stakeholder working groups, shall finalize the assessment study scope, including the identification of those transmission needs that will be studied, such as transmission needs driven by Public Policy Requirements, as further described in the Integrated Transmission Planning Manual. The study scope shall take into consideration the input requirements described in Section III.6.

e) The assessment study scope shall be posted on the SPP website and will be included in the published annual SPP Transmission Expansion Plan report. The assessment study scope shall include an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local and regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated.

f) In accordance with the assessment study scope, the Transmission Provider shall analyze potential solutions, including those upgrades approved by the SPP Board of Directors from the most recent 20-Year Assessment and 10-Year Assessment, following the process set forth in Section III.8.

6) Policy, Reliability, and Economic Input Requirements to Planning Studies

The Transmission Provider shall incorporate, as appropriate for the assessment being performed, the following into its planning studies:

a) NERC Reliability Standards;

b) SPP Criteria;

c) Transmission Owner-specific planning criteria as set forth in Section II;

d) Previously identified and approved transmission projects;

e) Zonal Reliability Upgrades developed by Transmission Owners, including those that have their own FERC approved local planning process, to meet local area reliability criteria;

f) Long-term firm Transmission Service;
### Tariff Revision Request (TRR)

<table>
<thead>
<tr>
<th></th>
<th>Description</th>
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<tbody>
<tr>
<td>g)</td>
<td>Load forecasts, including the impact on load of existing and planned demand management programs, excluding demand response resources;</td>
</tr>
<tr>
<td>h)</td>
<td>Capacity forecasts, including generation additions and retirements;</td>
</tr>
<tr>
<td>i)</td>
<td>Existing and planned demand response resources;</td>
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<tr>
<td>j)</td>
<td>Congestion within SPP and between the SPP Region and other regions and balancing areas;</td>
</tr>
<tr>
<td>k)</td>
<td>Renewable energy standards;</td>
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<td>l)</td>
<td>Fuel price forecasts;</td>
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<tr>
<td>m)</td>
<td>Energy efficiency requirements;</td>
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<td>n)</td>
<td>Other relevant environmental or government mandates;</td>
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<tr>
<td>o)</td>
<td>Transmission needs driven by Public Policy Requirements identified through a survey of stakeholders to identify Public Policy Requirements and additional transmission needs driven by Public Policy Requirements as determined by the Transmission Provider and stakeholders during study scope development by the Transmission Provider and stakeholders; and</td>
</tr>
<tr>
<td>p)</td>
<td>Other input requirements identified during the stakeholder process.</td>
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<tr>
<td>q)</td>
<td>In developing the long term capacity forecasts, the studies will reflect generation and demand response resources capable of providing any of the functions assessed in the SPP planning process, and can be relied upon on a long-term basis. Such demand response resources shall be permitted to participate in the planning process on a comparable basis. These studies will consider operational experience gained from markets operated by the Transmission Provider.</td>
</tr>
</tbody>
</table>

7) **Inclusion of Upgrades Related to Transmission Service and Generator Interconnection in Planning Studies**

   a) Transmission upgrades related to requests for Transmission Service are described in Sections 19 and 32 of the Tariff and Attachment Z1 to the Tariff. These upgrades are included as part of the future expansion of the Transmission System, upon the execution of the various Service Agreements with the Transmission Customers. Transmission upgrades related to an approved request for Transmission Service may be deferred or supplemented by other upgrades based upon the results of subsequent studies. Changes in planned upgrades do not
remove the obligation of the Transmission Provider to have adequate transmission facilities available to start or continue the approved Transmission Service.

b) Interconnection facilities and other transmission upgrades related to requests for generation interconnection service are described in Attachment V. These upgrades are included as part of the future expansion of the Transmission System upon the execution of the various interconnection agreements with the Generation Interconnection Customers. Transmission upgrades related to an approved interconnection agreement may be deferred or supplemented by other upgrades based upon the results of subsequent studies. Changes in planned upgrades do not remove the obligation of the Transmission Provider to have adequate transmission facilities available to start or continue the approved interconnection service.

c) The studies performed under this Section III of Attachment O shall accommodate and model the specific long-term firm Transmission Service of Transmission Customers and specific interconnections of Generation Interconnection Customers no later than when the relevant Service Agreements and interconnection agreements are accepted by the Commission.

8) Process to Analyze Transmission Alternatives for each Assessment

The following shall be performed, at the appropriate time in the respective planning cycle, for the 20-Year Assessment, 10-Year Assessment and Near Term Assessment studies:

a) The Transmission Provider shall perform the required studies to analyze the potential alternatives for improvements to the Transmission System, provided by the Transmission Provider and by the stakeholders, in order to address the final assessment study scope agreed to with the stakeholders. This analysis shall consider the current and anticipated future needs of the SPP Region within the parameters of the study scope. The analysis shall also consider the value brought to the SPP Region by incremental changes to the proposed solutions.

b) After the study scope has been approved, the Transmission Provider shall notify stakeholders of identified transmission needs and provide a transmission planning response window of thirty (30) days during which any stakeholder may propose a detailed project proposal (“DPP”). The Transmission Provider shall track each DPP and retain the information submitted pursuant to Section III.8.b(i). If the project described in a DPP is included in the ITP plan, the submitting stakeholder may qualify for incentive points as described in Section III of Attachment Y of this Tariff. A stakeholder that submits a DPP that is equivalent to a DPP or Transmission Provider identified project submitted in a previous assessment during the current three (3) year planning cycle shall not be eligible for incentive points.
i) The information supplied by the stakeholder must be sufficient to allow the Transmission Provider to evaluate the project described in the DPP. At a minimum, the DPP must include the following information:

a. description of the project including one-line diagrams, configuration(s), proposed line routing, preliminary transmission line and substation engineering and design data;

b. description of the needs identified in the ITP process to be addressed;

c. proposed project schedule including, at a minimum timelines for completing regulatory, right-of-way, environmental, engineering, procurement and construction activities;

d. description of any known or anticipated risks to the project schedule and any recommended mitigation plans;

e. description of any known or anticipated environmental impacts;

f. engineering and modeling data required by the Transmission Provider;

g. identification and justification of any changes in modeling assumptions from those used in the current ITP process;

h. results of transmission project economic or reliability analysis, if applicable; and

i. any other information available to support the evaluation of the project.

ii) Any Stakeholder providing a DPP that meets the requirements set forth in Section III.8.b(i) of this Attachment O will be recorded by the Transmission Provider for the ITP planning assessment for the which the DPP was submitted, including the contact information of the stakeholder that submitted the DPP.

iii) If the Transmission Provider, in its sole discretion, determines that the information provided in a DPP is incomplete, the Transmission Provider shall provide written notice to the stakeholder that submitted the DPP. The stakeholder shall be permitted to cure the such deficiency by the later of the end of the transmission planning response window or 10 days after the Transmission Provider issues such notice. Failure to cure the deficiency
shall result in the submission being disqualified as a DPP.

iv) The Transmission Provider shall hold all DPPs in confidence until the thirty (30) day transmission planning response window has closed. Subsequent to the close of the transmission planning response window, information contained in a DPP shall be disclosed to stakeholders only as the Transmission Provider determines is necessary for review and documentation of the reason(s) why the DPP was or was not chosen in the current ITP assessment. The remaining information in the DPP will remain confidential.

v) A stakeholder that submits a DPP may remain eligible for incentive points, in accordance with Section III of Attachment Y of this Tariff, for the remainder of the current three (3) year planning cycle of the ITP process. In order for the stakeholder to maintain its eligibility for incentive points in any subsequent ITP assessment within the current three (3) year planning cycle, the stakeholder must resubmit the information required by Section III.8.b(1) of this Attachment O, including identification of the need(s) in the ITP assessment that the DPP is proposed to solve. If the stakeholder does not provide the updated information, the stakeholder will not be eligible for incentive points for the DPP for that subsequent assessment; however, the stakeholder would be eligible for incentive points in any other ITP assessment during the current three (3) year planning cycle, provided that the stakeholder updates the DPP information for that assessment.

c) For all potential alternatives provided by the stakeholders, including reliability upgrades that Transmission Owners (which includes those Transmission Owners that have their own FERC approved local planning process), propose to address violations of company-specific planning criteria pursuant to Section II.5 of this Attachment O, and upgrades to address transmission needs driven in whole or in part by identified Public Policy Requirements, the Transmission Provider shall determine if there is a more comprehensive regional solution to address the reliability needs, economic needs, and needs driven by Public Policy Requirements identified in the assessment.

d) In addition to recommended upgrades, the Transmission Provider will consider, on a comparable basis, any alternative proposals which could include, but would not be limited to, generation options, demand response programs, “smart grid” technologies, and energy efficiency programs. Solutions will be evaluated against each other based on a comparison of their relative effectiveness of performance and economics.
The Transmission Provider shall assess the cost effectiveness of proposed solutions. Such assessments shall be performed in accordance with the Integrated Transmission Planning Manual, which shall be developed by the Transmission Provider, in consultation with stakeholders, and approved by the Markets and Operations Policy Committee. SPP shall post this manual on its website.

The analysis described above shall take into consideration the following:

i) The financial modeling time frame for the analysis shall be 40 years (with the last 20 years provided by a terminal value).

ii) The analysis shall include quantifying the benefits resulting from dispatch savings, loss reductions, avoided projects, applicable environmental impacts, reduction in required operating reserves, interconnection improvements, congestion reduction, and other benefit metrics as appropriate.

iii) The analysis shall identify and quantify, if possible, the benefits related to any proposed transmission upgrade that is required to meet any regional reliability criteria.

iv) The analysis scope shall include different scenarios to analyze sensitivities to load forecasts, wind generation levels, fuel prices, environmental costs, and other relevant factors. The Transmission Provider shall consult the stakeholders to guide the development of these scenarios.

v) The results of the analysis shall be reported on a regional, zonal, and state-specific basis.

vi) The analysis shall assess the net impact of the transmission plan, developed in accordance with this Attachment O, on a typical residential customer within the SPP Region and on a $/kWh basis.

The Transmission Provider shall make a comprehensive presentation of the preferred potential solutions, including the results of the analysis above, to the stakeholder working groups and at a planning summit meeting or web conference. The presentation shall include a discussion of all the Transmission Provider and stakeholder alternatives considered and reasons for choosing the particular preferred solutions.

The Transmission Provider shall solicit feedback on the solutions from the stakeholder working groups and through the stakeholders attending the various planning summits. The Transmission Provider will also include feedback from
stakeholders through other meetings, teleconferences, web conferences, and via email or secure web-based workspace. Stakeholders may propose any combination of demand resources, transmission, or generation as alternate solutions to identified reliability and economic needs.

i) Upon consideration of the results of the cost effectiveness analysis and feedback received in the subsequent review process, the Transmission Provider shall prepare a draft list of projects for review and approval in accordance with Section V.

V. The SPP Transmission Expansion Plan Report

The SPP Transmission Expansion Plan shall be a comprehensive listing of all transmission projects in the SPP for the twenty-year planning horizon. Projects included in the SPP Transmission Expansion Plan are: 1) upgrades required to satisfy requests for Transmission Service; 2) upgrades required to satisfy requests for generation interconnection; 3) approved projects from the 20-Year Assessment, 10-Year Assessment and Near Term Assessment (ITP Upgrades); 4) upgrades within approved Balanced Portfolios; 5) approved high priority upgrades; 6) endorsed Sponsored Upgrades; and 7) approved Interregional Projects. A specific endorsed Sponsored Upgrade will be included in the Transmission System planning model upon execution of a contract that financially commits a Project Sponsor to such upgrade or when such upgrade is otherwise funded pursuant to the Tariff. An approved Interregional Project will be included in the Transmission System planning model upon approval for construction in accordance with Section IV.6 of this Attachment O. To be included in the SPP Transmission Expansion Plan, each project must have been endorsed or approved through its proper process. This Section V describes the process used to approve or endorse the specific upgrades identified in 20-Year, 10-Year and Near Term Assessments, high priority upgrades, and Balanced Portfolios. [The SPP Transmission Expansion Plan shall also identify whether any approved Competitive Upgrades, as that term is defined in Attachment Y of this Tariff, causes reliability violations on an adjacent neighboring transmission system, as described in more detail in Section V.7 of this Attachment O.]

1) Development of the Recommended Set of Upgrades from Planning Studies

a) Upon completion of the analysis, studies and stakeholder review and comment on the results in accordance with Sections III and IV of this Attachment O, the Transmission Provider shall prepare a draft list of all projects for review by the stakeholders. The Transmission Provider shall post the draft project list on the SPP website and shall identify the assessment process with which they are associated.

b) Upon posting of the draft project list, the Transmission Provider shall invite written comments to be submitted to the Transmission Provider.

c) The Transmission Provider shall review the draft project list with the stakeholder
d) Considering the input from the stakeholders through this review process, the Transmission Provider shall prepare a recommended list of proposed ITP Upgrades based upon the analysis as described in Section III, upgrades within proposed Balanced Portfolios, and proposed high priority upgrades for review and approval.

2) Disclosure of the Recommended Set of Upgrades and Supporting Information from Planning Studies

a) The Transmission Provider shall disclose planning information, which includes the recommended list of proposed upgrades and the underlying studies, by providing:

i) All stakeholders equal access, notice and opportunity to participate in planning summits, the stakeholder working group meetings and the sub-regional planning meetings as well as any associated web conferences or teleconferences as set forth in Section II of this Attachment O; and

ii) For the contemporaneous availability of such meeting handouts on the SPP website.

b) The related study results, criteria, assumptions, analysis results, and data underlying the studies used to develop the proposed ITP Upgrades, the list of upgrades within proposed Balanced Portfolios, and proposed high priority upgrades shall be posted on the SPP website, with password protected access if required to preserve the confidentiality of information in accordance with the provisions of the Tariff and the SPP Membership Agreement and to address CEII requirements. Additionally, Transmission Owner specific local plans and criteria shall be accessible via an electronic link on the SPP website in accordance with Section VII of this Attachment O. The CEII compliant redacted version of the SPP Transmission Expansion Plan and individual Transmission Owner specific local plans shall be posted on the SPP website. Redacted versions shall include instructions for acquiring the complete version of the SPP Transmission Expansion Plan and individual Transmission Owner specific local plans. An electronic link shall be provided on the SPP website by which stakeholders may send written comments on the SPP Transmission Expansion Plan and Transmission Owner specific local plans and criteria.

3) Approval and Endorsement Process

a) The Markets and Operations Policy Committee shall make a recommendation regarding the approval of ITP Upgrades. Approval by the SPP Board of Directors is required for the inclusion of ITP Upgrades in the SPP Transmission Expansion
b) The Markets and Operations Policy Committee shall make a recommendation regarding the inclusion of a proposed Balanced Portfolio in the SPP Transmission Expansion Plan. Approval by the SPP Board of Directors is required for inclusion of a Balanced Portfolio in the SPP Transmission Expansion Plan. SPP is not required to have a Balanced Portfolio each year.

c) If the SPP Board of Directors approves a list of ITP Upgrades, upgrades within Balanced Portfolios, or high priority upgrades other than those recommended by the Markets and Operations Policy Committee, the explanation for the deviation shall be included in the SPP Transmission Expansion Plan.

d) The Markets and Operations Policy Committee shall make a recommendation regarding the approval of a high priority upgrade recommended by the Transmission Provider. Approval by the SPP Board of Directors is required for the inclusion of a high priority upgrade in the SPP Transmission Expansion Plan.

e) The Markets and Operations Policy Committee shall make a recommendation regarding endorsement of a proposed Sponsored Upgrade. Endorsement by the SPP Board of Directors is required for the inclusion of a Sponsored Upgrade in the SPP Transmission Expansion Plan.

f) The list of projects shall be posted on the SPP website by the Transmission Provider. The Transmission Provider shall, in addition to the posting, e-mail notice of such posting to the stakeholders at least ten days prior to a meeting at which the SPP Board of Directors is expected to take action on accepting or modifying the list.

g) The list of approved ITP Upgrades, upgrades within approved Balanced Portfolios, approved high priority upgrades, and endorsed Sponsored Upgrades may be modified throughout the year by the SPP Board of Directors provided that such action shall be posted and noticed pursuant to this section.

h) The list of upgrades for Transmission Service are approved in accordance with the provisions of Attachment Z1 and included in the STEP accordingly.

i) The list of interconnection facilities and other transmission upgrades related to requests for generation interconnection service are approved in accordance with the provisions of Attachment V and included in the STEP accordingly.

j) The list of Interregional Projects is approved in accordance with Section IV.6 of this Attachment O and included in the STEP accordingly.
k) The SPP Transmission Expansion Plan shall be presented to the SPP Board of Directors at least once a year. Approval of the ITP Upgrades, Balanced Portfolios, and high priority upgrades, and the endorsement of the other projects contained in the SPP Transmission Expansion Plan by the SPP Board of Directors shall certify a regional plan for meeting the transmission needs of the SPP Region.

4) Updates to the SPP Transmission Expansion Plan
   a) Modifications to the SPP Transmission Expansion Plan may be made between the annual approvals as required to maintain system reliability and to meet new business opportunities as they are identified.
   b) The Transmission Provider shall work with the stakeholders on an on-going basis throughout the year analyzing any newly identified issues and incorporating any necessary adjustments to the SPP Transmission Expansion Plan on an out of cycle basis.
   c) On a quarterly basis, the Transmission Provider shall post any modifications to the SPP Transmission Expansion Plan on the SPP website.
   d) The modifications shall be reviewed by the stakeholders and the Regional State Committee, endorsed by the stakeholder working groups, and approved or endorsed by the SPP Board of Directors, in accordance with Section V of this Attachment O.

5) Removal of an Upgrade from the SPP Transmission Expansion Plan.

   The Transmission Provider, in consultation with the stakeholders in accordance with Section V of this Attachment O, may remove an upgrade from an approved SPP Transmission Expansion Plan. A Transmission Owner that has incurred costs related to the removed upgrade shall be reimbursed for any expenditure pursuant to Section VIII of Attachment J to the Tariff.

6) Status of Upgrades Identified in the SPP Transmission Expansion Plan
   a) The Transmission Provider shall track the status of planned system upgrades to ensure that the projects are built in time or that acceptable mitigation plans are in place to meet customer and system needs.
   b) On a quarterly basis, at a minimum, the Transmission Provider shall:
      i) Report to the Markets and Operations Policy Committee, the Regional State Committee and the SPP Board of Directors on the status of the upgrades
identified in the SPP Transmission Expansion Plan; and

ii) Post the status of the upgrades on the SPP website.

Impacts on Adjacent Systems

As part of the evaluation of any Competitive Upgrade, the Transmission Provider will determine, based on its planning model, whether a proposed Competitive Upgrade causes any reliability violations on the transmission system of an adjacent transmission planning region. The Transmission Provider shall identify any such violations as part of the transmission planning process that identified the Competitive Upgrade. Except as otherwise provided in this Tariff or as otherwise provided in an agreement between the Transmission Provider and an adjacent transmission system, the Transmission Provider shall not pay any cost for any upgrade or system modification necessary to mitigate or resolve any such violation on an adjacent transmission system, and listing of such violations in the SPP Transmission Expansion Plan does not constitute any agreement on the part of the Transmission Provider or its stakeholders to pay any such cost.

Proposed Market Protocol Language Revision (Redlined)

n/a

Proposed Business Practices Language Revision (Redlined)

n/a
### Proposed Criteria Language Revision (Redlined)

n/a

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### Revisions to Other Corporate Documents (Redlined)

n/a

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Background
The Federal Energy Regulatory Commission (FERC) directed SPP to make a further compliance filing to establish a stated dollar amount, or a formula, that a prospective transmission developer must submit with its bid. Staff recommended compliance proposals to the Strategic Planning Committee Task Force on Order 1000 (SPCTF). The SPCTF approved a modified recommendation for the initial bid deposit equaling $50,000 and forwarded that recommendation to the Regional Tariff Working Group (RTWG) for incorporation into the compliance tariff Filing. The Market and Operations Policy Committee (MOPC) upon consideration further modified the initial bid deposit amount to $10,000. The Strategic Planning Committee (SPC) debated the modifications made by the MOPC and tasked the staff to develop a formulaic alternative for Board consideration.

Analysis
The FERC issued its Order on SPP’s Order 1000 Intraregional Compliance Filing on July 18, 2013. Among other items FERC directed SPP to file OATT revisions that establish a precise dollar amount, or a formula, for establishing the dollar amount of the initial fee that a prospective transmission developer must submit with its bid.

The SPCTF approved Staff’s proposal to change the reference, “initial fee”, to “bid deposit”. The proposal would have Bidders submit a per bid deposit which SPP will hold in a segregated interest bearing account in the name of the bidder tied to the bidder’s tax identification number. The deposit will “secure” the bidder’s share of the costs for SPP to perform the process. Once the process is completed and the bids awarded SPP would calculate the total costs to administer the process and deduct that cost, on a per bid basis, from each bidder’s deposit account. Thereafter, all remaining deposits, and interest earned on those deposits, will be returned to the bidders.

Based upon the guidance of the Finance Committee, the bid deposit should be set at a large enough level to truly indicate the seriousness and intent of the bidders to participate in the process without being so large as to significantly limit the financial ability of bidders to participate and further to collect from bidders dollar amounts sufficient enough to cover a sizable amount of the costs associated with administering the RFP process. Accordingly, Staff proposed to the SPCTF an initial bid deposit of $100,000.

The SPCTF modified the initial bid deposit proposal to $50,000 on the basis that $100,000 seemed too high. This modified recommendation was provided to the RTWG for incorporation into the compliance tariff and they adopted it for their compliance recommendation to the MOPC. The MOPC further modified the recommendation of the RTWG regarding the bid deposit amount and changed it to $10,000 with the rationale that $50,000 could potentially prohibit participation, especially amongst smaller entities. The SPC debated the MOPC’s further modification and did not endorse the lower amount because of the view that the cost of the bidding process is to be borne by the bidders and not SPP’s members. Following a robust discussion that included suggestions that the Board would like to consider a formulaic approach staff agreed to develop such an alternative for the Board’s consideration.

Staff worked with several members to develop a three-tiered bid deposit. This three-tier approach proposes differing levels of bid deposits based upon the estimated cost of a transmission project. The table below shows the bid deposit amounts.
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<tr>
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<th>Small Proposal</th>
<th>Medium Proposal</th>
<th>Large Proposal</th>
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<tr>
<td></td>
<td>(&lt; $10M) or Localized Problem</td>
<td>(&lt; $10M to $100M) or 2-Zone Problem</td>
<td>(&gt; $100M) or Multi-Zone or Network Problem</td>
</tr>
<tr>
<td>Bid Deposit</td>
<td>$10,000</td>
<td>$25,000</td>
<td>$50,000</td>
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Using recent history as a basis to categorize levels of transmission costs, most byway projects would be at the lower bid deposit levels while highway projects would logically require higher bid deposits.

The three-tiered bid deposit system uses a simplistic formula that makes it easier for proposers to know what their “up-front” costs will be, it more appropriately allocates the cost of the IEP process by keeping smaller projects from subsidizing the analysis associated with larger projects, makes it easier for smaller entities to participate in the process without significantly limiting their financial ability to participate, ensures that costs associated with the bidding process are paid for by those who are bidding and not by SPP’s members and customers, and lastly aligns the expected cost of analysis by the expected level of project complexity.

**Action Requested:** Board consideration as an alternative to fixed $10,000 bid deposit recommended by the MOPC.
Order 1000
Bid Deposit Alternative

October 29, 2013

Michael Desselle
mdesselle@spp.org · 501.614.3206
Three Tier Bid Deposit

<table>
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<tr>
<th>Bid Deposit</th>
<th>Small Proposal (&lt; $10M) or Localized Problem</th>
<th>Medium Proposal (&lt; $10M to $100M) or 2-3 Zone Problem</th>
<th>Large Proposal (&gt; $100M) or Multi-Zone or Network Problem</th>
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<tr>
<td>$10,000</td>
<td>$25,000</td>
<td>$50,000</td>
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Advantages

• Bidders pay for costs of bidding process
• Bidders will know “up-front” costs
• Prevents smaller project subsidization of larger projects
• Eases small entity participation
• Aligns expected cost of analysis by expected level of complexity
• With multiple bids, analysis costs should decrease
Southwest Power Pool, Inc.
MARKETS AND OPERATIONS POLICY COMMITTEE
Recommendation to the Board of Directors
MPPRs 130 & 145
October 29, 2013

Organizational Roster
The following members represent the Market Working Group:

- Richard Ross, AEP, Chairman
- Gene Anderson, OMPA, Vice Chairman
- Will Amos, OGE
- Lee Anderson, Lincoln Electric System
- Amber Metzker, Xcel Energy
- Neal Daney, KMEA
- Jim Flucke, KCPL
- Clifford Franklin, Westar Energy, Inc.
- Matt Johnson, City Utilities, Springfield, MO
- Chris Lyons, Constellation Energy Commodities Group
- Rick McCord, EDE
- Matt Moore, Golden Spread Electric Cooperative
- Aaron Rome, Midwest Energy, Inc.
- Ann Scott, Tenaska Power Services Co.
- Mike Swearingen, Tri-County Electric Cooperative, Inc.
- Ron Thompson, NPPD
- Bruce Walkup, AECC
- Rick Yanovich, OPPD
- Debbie James, SPP, Secretary

Background
Please see the MPRR Recommendation Report for MPPRs 130 & 145 that were included in the MOPC October 15-16, 2013 background materials.

Analysis
Please see the MPRR Recommendation Report for MPPRs 130 & 145 that were included in the MOPC October 15-16, 2013 background materials.

Recommendation
The MWG recommends that the MOPC approve its request regarding Marketplace Protocol Revision Requests MPPRs 130 & 145.

Action Requested: Approval of MWG’s request on MPPRs 130 & 145
APPROVAL: MOPC October 15-16, 2013

Approved MPRR 130 with five opposed-KGE Westar, Xcel Energy, Exelon, Westar Energy Prairie Wind Transmission and four abstentions-ITC Great Plains, KPP, KEPC & City of Coffeyville

Approved MPRR 145 as modified with seven abstentions-ITC Great Plains, Flat Ridge 2 Wind Energy, NPPD, NextEra, Dogwood Energy, City of Coffeyville, and Exelon.

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<tr>
<th>MPRR Number</th>
<th>Description</th>
<th>MWG Meeting Vote</th>
<th>RTWG Meeting Vote</th>
<th>ORWG Meeting Vote</th>
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<tr>
<td>145</td>
<td>Head-room/Floor-room Capacity Requirements</td>
<td>9/18/2013 Approved</td>
<td>9/25/2013 Approved with modifications</td>
<td>10/1/2013 Approved</td>
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# PRR Recommendation Report

<table>
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<tr>
<th>PRR No.</th>
<th>Marketplace-PRR130</th>
<th>PRR Title</th>
<th>Must Offer Penalty Calculation and Rules</th>
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## Timeline

- **Normal**
- **Expedited**
- **Urgent Action**

Provide explanation if Expedited and/or Urgent Action is selected:

## Recommendation Action

- **Approve**
- **Reject**
- **Require additional information**
- **Defer**
- **Refer**

## Impact Analysis Required

- **Yes** – If yes, estimated cost:
- **No**

**SPP Staff will complete this section.**

## Protocol Section(s) Requiring Revision

- **Section No.**: 4.1.2.1.5, 4.1.3, 4.2.1, 4.2.1.1, 4.2.1.1.1 (new), 4.5.11, 8.1.4.2, 8.2.7, 8.2.7.1
- **Title**: Reserve Zone Load, Operating Reserve Requirements, Must-Offer Requirement, Day-Ahead Market, Penalty Calculation (new), Miscellaneous Amount, Monitoring Activities, Sanctions for Noncompliance with the Day-Ahead Market Must-Offer Requirement, Penalty Calculation
- **Protocol Version**: 16.0a

## Type of Revision

- **Correction/Clean-Up**
- **Clarification**
- **Design Enhancement**
- **Design Change**

## Timeline

- **Go-Live**
- **Post Go-Live**

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**Revision Description**

After MCRR 16 was approved, there were still questions and issues that were not addressed in the MCRR due to compliance deadlines. Some members believed that the design was administratively burdensome considering there were still many ways to sidestep the requirement. MWG redesigned the Must-Offer in order to better serve more members while reducing unnecessary administration of the requirement.

This design of the Day-Ahead (DA) must-offer requirement moves the requirement from the Market Participant (MP) granularity to Asset Owner (AO) granularity so that other AOs under and MP who offered everything do not get assessed part of a penalty because of one noncompliant AO under the same MP.

1. First, a market-wide check is done. If the DA Market clears hourly with sufficient capacity system-wide to meet fixed Demand Bids and fixed Export Interchange Transaction Bids plus Operating Reserve (OR) [4.3.1.2(1)(a)(i)], then no further checks will be done.

2. (a) However, if SPP must implement procedures in 4.3.1.2(1)(a)(i) for an hour in order to clear the DA Market, then SPP will check each Asset Owner to determine if all required Resources were offered in the DA Market with a Commitment Status of Market or Self. Variable Energy Resources (VERs), Demand Response Resources (DRRs), and Resources with a Commitment Status of Outage are not required to be offered. If an AO has no Resources with a Commitment Status of Reliability or Not Participating, then that AO is compliant.

2. (b) If the AO has a Resource with a Commitment Status of Reliability or Not Participating, then...
Participating, but offers enough to cover (i) OR plus (ii) fixed firm Exports plus (iii) 90% of its Reported Load, then that AO is compliant.

(2)(c) If an AO does not offer enough to cover its OR, Exports, and 90% of its Reported Load, then the Market Monitoring Unit (MMU) will make contact. If the AO offered Resources plus the net of firm power purchases and sales plus Real-Time (RT) purchase power agreement obligation sufficient to meet its OR, Exports, and 90% of its Reported Load, then that AO is in compliance.

(2)(d) If the AO fails the above tests, then it will be assessed an hourly penalty based on not-offered MWs and the difference between the weighted average of the price difference between DA and hourly RT. The penalty will be distributed to compliant AOs for the hour via the miscellaneous charge type. The penalty is located with the rules and not in the market monitoring section since the must-offer requirement is an SPP rule and not a market monitor’s rule. The market monitoring section only states what will be monitored.

<table>
<thead>
<tr>
<th>Tariff Implications or Changes</th>
<th>X Yes – Section No: <em>(Include a summary of impact and/or specific changes)</em></th>
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<tbody>
<tr>
<td></td>
<td>Attachment AE (2.11.1, 2.11.1.1, 3.1.4), Attachment AF (4.2)</td>
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<td>Criteria Impact or Changes</td>
<td>X Yes – Section No: <em>(Include a summary of impact and/or specific changes)</em></td>
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<tr>
<td>MWG Review</td>
<td>Date of Vote: 9/3/2013  Vote: Approved</td>
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<tr>
<td></td>
<td>Opposed: Excel, Westar</td>
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<tr>
<td></td>
<td>Abstained: N/A</td>
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<tr>
<td></td>
<td>Date of Vote: 9/17/2013  Vote: Unanimously Approved RTWG modifications</td>
</tr>
<tr>
<td></td>
<td>Opposed: N/A</td>
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<tr>
<td></td>
<td>Abstained: N/A</td>
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<tr>
<td>RTWG Review</td>
<td>Date of Vote: 9/11/2013  Vote: Approved with modifications</td>
</tr>
<tr>
<td></td>
<td>Opposed: Excel</td>
</tr>
<tr>
<td></td>
<td>Abstained: WR, TNSK, GSEC</td>
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<tr>
<td>ORWG Review</td>
<td>Date of Vote: 9/12/2013  Vote: Approved</td>
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<td>MOPC Recommendation</td>
<td>Date of Vote:</td>
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<td>Board Review</td>
<td>Date of Vote:</td>
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<td>Vote:</td>
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<td>Date</td>
<td>6/3/2013</td>
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<tr>
<td>Sponsor</td>
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</tr>
<tr>
<td>Name</td>
<td>Jared Greenwalt</td>
</tr>
<tr>
<td>E-mail Address</td>
<td><a href="mailto:jgreenwalt@spp.org">jgreenwalt@spp.org</a></td>
</tr>
<tr>
<td>Company</td>
<td>Southwest Power Pool</td>
</tr>
<tr>
<td>Phone Number</td>
<td>501.688.8314</td>
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### Reasons for Opposing

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<tr>
<th>Dissenter</th>
<th>Excel</th>
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<tr>
<td>Date</td>
<td>9/3/2013</td>
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**Reason**

I voted no to MPRR 130 due to the following reasons:

1. Discomfort that units in reserve shutdown are exempt from day ahead must offer.
2. Discomfort that there will no longer be a daily check on the day ahead must offer provisions and it will only be done when the day ahead market is not deemed resource-sufficient.
3. Discomfort in the lack of clarity on how the firm purchases, firm sales, and real-time purchase power agreement obligations will work in accordance to the must offer language.

### Reasons for Opposing

<table>
<thead>
<tr>
<th>Dissenter</th>
<th>Westar</th>
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<tr>
<td>Date</td>
<td>9/3/2013</td>
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**Reason**

Westar generally supports the Limited Must Offer framework of MPRR 130. However, Westar votes no due to unjustified Must Offer capacity exemptions. MPRR 130 erroneously provides exemptions for both Reserve Shutdown Outage capacity and Demand Side Resource capacity. Must Offer exemptions should only be provided exclusively for capacity mechanically/operationally unavailable or intermittent/uncontrollable resources.

### Comments Received

<table>
<thead>
<tr>
<th>Comment Author</th>
<th>Fred Mitro (Flat Ridge 2 Wind Energy LLC)</th>
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<tbody>
<tr>
<td>Date</td>
<td>6/14/2013</td>
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</table>

**Comment Description**

The tariff language proposed in MPRR 130 should be revised so that it is clear regarding Asset Owners that do not have any load. If an Asset Owner does not have any load, the Market Participant representing the Asset Owner should not have an affirmative obligation to submit an offer into the Day-Ahead market. In addition, such an Asset Owner should not be subject to any penalties for non-compliance with the Day-Ahead must offer requirement. This seems to be what was intended by the protocol and tariff language proposed in MPRR 130, given that 1) the must offer language requires an Asset Owner’s load to be covered and 2) resource deficiencies and penalty calculations are dependent on an Asset Owner’s load. However, given the potential for confusion about the scope of the Day-Ahead must offer obligation, Flat Ridge 2 believes that it would be beneficial if the tariff language were clear regarding the scope of the Day-Ahead must offer obligation and penalty and their inapplicability to Asset Owners that do not have load.

**Comment Status**

These comments were taken into consideration by the MWG. MWG did not make any language changes based on these comments at this time.

### Comments Received

<table>
<thead>
<tr>
<th>Comment Author</th>
<th>Matthew Johnson (The Energy Authority)</th>
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<tr>
<td>Date</td>
<td>6/14/2013</td>
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**Comment Description**

This has long been a contentious issue at the MWG and MOPC that we have been in staunch opposition of for the following reasons:

1. We believe that market economics should dictate participant behavior.
2) We believe this approach is onerous and overcomplicated
3) Stakeholders have consistently struggled to reach consensus
4) Requirements are discriminatory (do not apply to IPPs and LSE’s without generation)
5) Requirements are not cost effective to administer for SPP and stakeholders
6) Requirements do not adequately address wind farms
7) Requirements could expose stakeholders to undue exposure to FERC and potential financial penalties.

We are unable to come up with a defensible argument for why SPP should have a Day Ahead Must-Offer Requirement, in light of an existing Real Time Must-Offer Requirement. As such, we respectfully submit to the Market Working Group this request for removal of this requirement from the Integrated Marketplace, effectively imposing “No Day Ahead Must Offer Requirement”. We believe this change would not adversely affect market systems or Integrated Marketplace Go Live.

We request removal of the Day Ahead Must - Offer Requirement.

Comment Status
These comments were taken into consideration by the MWG. MWG did not make any language changes based on these comments at this time.

<table>
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<tr>
<th>Comment Status</th>
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<tr>
<td>These comments were taken into consideration by the MWG. MWG did not make any language changes based on these comments at this time.</td>
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<td>Date</td>
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<td>Comment Description</td>
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FERC understands and specifically recognized the existing limited Day Ahead Must Offer for the SPP Integrated Marketplace resulted from a deliberative stakeholder process that attempted to balance multiple goals such as reliability and flexibility for Market Participants. FERC has also stated that the existing SPP design strikes a reasonable balance between providing Market Participants flexible offer requirements and ensuring that Market Participants offer sufficient resources to hedge load obligations. FERC has also stated that the existing SPP Day Ahead Must Offer design is just and reasonable in that it does not need to apply MP’s that do not serve load.

FERC has also indicated that the Commission has NOT required and indeed REJECTED in some instances a Day Ahead Must Offer requirement in other RTO’s and ISO’s in scenarios where there are no centralized capacity payment compensation methods. This conceptually includes any notion that only Network Designated Resources should be required to offer in Day Ahead.

FERC has also indicated they do NOT believe that the existing DA Must Offer Design would create artificially high prices, create any gaming or manipulation, encourage any physical withholding, or result in substantially any fewer benefits in the market as a result of the existing approved design.

Specifically addressing TEA comments, although many of the TEA points made are TEA opinions, GSEC respectively believes those opinions should be addressed at FERC. However, GSEC will attempt to address two of the seven
points expressed by TEA.

GSEC believes that LSE’s inside of SPP are required to have excess capacity in place for planning purposes. As a result, there should be no LSE without Firm deliverable power either in ownership or contract. In the event, the LSE obligation is covered via contract, the LSE should be currently discussing the parameters of the individual specific contracts as it pertains to optionality within that contract for the SPP IM. At a minimum, an LSE will have Day-Ahead rights to the volume in the contract and therefor will have an opportunity to cover a large percentage of their load Day Ahead. In this scenario, the seller of the contract is already aware of the parameters they have sold the LSE. As such there should be no issue with Day Ahead operations. In the event, the generator is not owned by an LSE or contracted with an LSE, then as FERC clearly indicated the Day Ahead obligation does not apply.

In regards to wind farms, there are incentives and impacts that drive wind behavior. In the event, the wind farm is considered to be Firm deliverable power; the off-taker can use the resource towards their Day Ahead Must Offer. However, the MP would be considering the financial ramifications of producing at a lower volume than what is cleared Day Ahead. In the event, there is a wind farm that isn’t considered Firm deliverable; it would not count towards the Day Ahead Must Offer.

All of the other TEA comments appear to be subjective. GSEC would respectively suggest that a Must Offer Penalty Calculation and Penalty MPRR quickly be approved in response to the original FERC order directive.

| Comment Status | These comments were taken into consideration by the MWG. MWG did not make any language changes based on these comments at this time. |

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### Comments Received

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<tr>
<th>Comment Author</th>
<th>Debbie James on behalf of the MWG Chair</th>
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<tr>
<td>Date</td>
<td>8/16/2013</td>
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<tr>
<td>Comment Description</td>
<td>My attempt, as MWG chair, is to simplify this limited must offer so that the effort required to comply, monitor, and administer it is commensurate with the benefit it provides the operation of the market. The purpose of the must offer is to incent actual assets to offer into the market, so no BSSs should be considered when determining if an Asset Owner is compliant. If an Asset Owner has a Resource with a Commitment Status of Reliability or Not Participating, and the sum of its offers is less than its load, then the net of all BSSs at a Resource Settlement Location will be used to offset the Not Offered, Available MWs.</td>
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<tr>
<td>Comment Status</td>
<td>These comments were taken into consideration by the MWG. MWG did not make any language changes based on these comments at this time.</td>
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<table>
<thead>
<tr>
<th>Comment Author</th>
<th>Cliff Franklin (Westar Energy, Inc.)</th>
</tr>
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<tr>
<td>Date</td>
<td>8/16/2013</td>
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<tr>
<td>Comment Description</td>
<td>Originally, SPP had proposed using a Market Participants (MPs) SPP Mid-Term Load forecasts and reserve obligation in determining DA Limited Must-Offer compliance. Westar has always supported this concept. The original proposal provided MPs clarity needed to meet the SPP DA Limited Must-Offer threshold. The current language changed the original SPP proposal to base the Must-Offer compliance on actual RT reported load. Westar submits here that the original proposal is better and amends the protocols and tariff language back to using</td>
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SPP’s DA Mid-Term Load Forecasts for meeting Must-Offer compliance. See amendments for Protocol and Tariff language in MPRR 130.

Westar also proposes MPs that put resources on “reliability only” status or put resources on “reserve shutdown” outage should treated comparatively for SPP’s Limit Must-Offer compliance. Although, Westar acknowledges that there are good reasons to put resources on “reserve shutdown” outage or assign “reliability only” status, there is no significant differences between the two.

**Comment Status**
These comments were taken into consideration by the MWG. MWG did not make any language changes based on these comments at this time.

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<th><strong>Comments Received</strong></th>
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<td><strong>Date</strong></td>
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<td><strong>Comment Description</strong></td>
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In Protocols 4.2.1.1.1, MWG chose to avoid confusion in the words “capacity” or “capability” by simply referring to not offered MWs. In that same section, MWG cleaned up the phrase “below the 10% tolerance band” to say “in excess of the 10%...” since “below” could mean within the tolerance band. Must-Offer Shortage MW was changed to Penalty MW so that it is not confused with the Shortage MW. MWG chose to put the exclusion of VERs and DRRs in the penalty calculation to emphasize that they are excluded. Additionally, in the penalty calculation, MWG added the words “hourly, weighted average” because RT LMPs are calculated every five minutes, and the DA LMP is hourly. This makes both LMPs hourly values.

Sections 8.2.7 was deleted since it was no longer part of the design, and the penalty calculation in 8.2.7.1 was moved to 4.2.1.1.1 since the MMU is not involved with implementing the Tariff. Other clean-up, formatting, and clarification language was changed. MWG added the Tariff language that reflects the Protocols in this document below.

**Comment Status**
The MPRR was approved as modified in these comments. The approved language is reflected in this recommendation report.

<table>
<thead>
<tr>
<th>Comment Status</th>
<th>The MPRR was approved as modified in these comments. The approved language is reflected in this recommendation report.</th>
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**Comments Received**

<table>
<thead>
<tr>
<th>Comment Author</th>
<th>Brenda Fricano on behalf of RTWG</th>
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<tbody>
<tr>
<td>Date</td>
<td>9/11/2013</td>
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</table>

| Comment Description | RTWG added bulleted Section 2.11.1 to make section references easier. RTWG simplified the opening paragraph of 2.11.1 so that it did not contradict the market-wide check. Instead of saying that the MP would not get a must-offer penalty if compliant in each check, the sentence was added before each check in the newly labeled Section E. “Firm power sales” was added since the documentation must be provided to the MMU in addition to Firm Power Purchases. The word “its” was replaced with “such Asset Owner’s” for clarity. RTWG also modified language to clarify that the Must Offer Penalty will be assessed on an Asset Owner level, but will roll up to the Market Participant. Additionally, RTWG made minor changes for clarity, formatting, and grammar. RTWG changes are highlighted in yellow. |
| Comment Status     | RTWG changes are highlighted in yellow. |

**Proposed Protocol Language Revision**

### 4.1.2.1.5 Reserve Zone Load

Using the PNode load forecasts developed under Section 4.1.2.1.6, SPP sums up the load forecasts at each PNode in a Reserve Zone to determine the amount of load within the Reserve Zone for input into the study models used to establish the daily Reserve Zone minimum and maximum Operating Reserve requirements. Additionally, SPP will calculate each Market Participants’ Asset Owner’s forecast load within each Reserve Zone and SPP will then use this Asset Owner Market Participant load forecast to estimate each Asset Owner’s Market Participant Operating Reserve obligation within each Reserve Zone.
4.1.3 Operating Reserve Requirements

SPP calculates the amount of Operating Reserve required for the Operating Day, on both a system-wide basis and a Reserve Zone basis, to comply with the reliability requirements specified in the SPP Criteria. SPP calculates the hourly Regulation-Up, Regulation-Down and Contingency Reserve requirements on an SPP BAA basis and calculates minimum Operating Reserve requirements and maximum Operating Reserve limitations for each Reserve Zone.

(1) SPP BAA Contingency Reserve requirements are set consistent with SPP Criteria and may vary on an hourly basis.

(2) SPP BAA Regulation-Up and Regulation-Down requirements are set to ensure compliance with NERC control performance requirements and are based upon a percentage of forecasted load, adjusted up or down to account for resource output variability, and may vary on an hourly basis.

(3) The SPP BAA requirements, minimum Reserve Zone Operating Reserve requirements and maximum Reserve Zone Operating Reserve limitations are calculated and posted no later than 7:00 AM Day-Ahead. At this time, SPP will also communicate each Asset Owner’s Market Participant’s estimated Operating Reserve obligations in each Reserve Zone using the BAA Mid-Term Load Forecast and the Asset Owner Market Participant load forecasts developed by SPP under Section 4.1.2.1.5.

(4) These Operating Reserve requirements and limitations are used by SPP as inputs into the DA Market and RTBM clearing and RUC processes.

   (a) SPP may increase Operating Reserve requirements for use in RTBM clearing and RUC processes above the requirements used in the DA Market clearing, including changes to Reserve Zone minimums and maximums, as required to meet increases in reliability requirements caused by changes in system conditions.

(5) Reserve Zone minimum Operating Reserve requirements and maximum Operating Reserve limitations are determined through reserve zone studies prior to the DA Market. Reserve zone studies are performed as described under Section 4.1.3.1.

4.2.1 Must-Offer Requirement

Market Participants are required to offer available Resources to the Day-Ahead Market, RUC, and RTBM as described in this section below. For the Day-Ahead Market, RUC and RTBM, Resource Offers must include: (i) a Start-Up Offer, a No-Load Offer and an Energy Offer Curve for Resources qualified to provide Energy; (ii) a Regulation-Up Offer for Regulation-Up
Qualified Resources and Regulation-Qualified Resources, (iii) a Regulation-Down Offer for Regulation-Down Qualified Resources and Regulation-Qualified Resources, (iv) a Spinning Reserve Offer for Spin-Qualified Resources and (v) a Supplemental Reserve Offer for Supplemental-Qualified Resources.

4.2.1.1 Day-Ahead Market

Each Market Participant must offer sufficient Resources to the Day-Ahead Market to cover each Asset Owner’s individual load plus Operating Reserve obligation to the extent the Asset Owner’s Resources are available (e.g. not on forced outage, planned outage or Reserve Shutdown).

For the must-offer requirement, in order for a Resource to be considered offered, it must have a Commitment Status of Market or Self. Variable Energy Resources, Demand Response Resources and Resources with a Commitment Status of Outage are not required to be offered.

A Market Participant’s Operating Reserve obligation for an Asset Owner, for the purposes of this section, shall be equal to the sum of that Market Participant’s Regulation-Up and Contingency Reserve obligation for that Asset Owner as calculated by SPP as described in Section 4.1.3 for the hour of the Operating Day.

For purposes of this section, Firm Power Purchases and Firm Power Sales shall mean purchases and sales that are deliverable with Firm Point-To-Point Transmission Service or Firm Network Integration Transmission Service, and the capacity and energy are supplied under standards of reliability and availability equivalent to supply of native load customers with the supplier assuming the obligation to provide both capacity and energy. Additionally, Firm Power purchases shall include an Asset Owner’s share of a Jointly Owned Unit to the extent that such shares have not been registered as individual Resources either under the JOU Individual Resource Option or the JOU Combined Resource Option as described under Section 4.2.2.5.4.

Supporting documentation for Firm Power Purchases and firm power sales must be provided to the Market Monitor when requested.

For the purposes of this section, Real-Time purchase power agreement obligations shall mean contractual commitments to make firm Energy available in Real-Time. Supporting documentation for Real-Time purchase power agreement obligations must be provided to the Market Monitor when requested.

(1) If the Day-Ahead Market clears for an hour of the Operating Day without executing the procedures described in Section 4.3.1.2.(1)(a)(i), then the Day-Ahead Market will be deemed Resource-sufficient for that hour, and no must-offer requirement penalties will be assessed for that hour.
(2) If the Day-Ahead Market does not clear as described in (1) above:

(a) A Market Participant that offers all Resources as described above in this section for an Asset Owner for that hour is in compliance with the must-offer requirement for that Asset Owner, and will not be assessed a must-offer requirement penalty for that Asset Owner for that hour of the Operating Day.

(b) A Market Participant that does not offer all Resources as described in (a) above, but offers Resources for an Asset Owner for that hour that is greater than or equal to the sum of its (i) Operating Reserve obligation plus (ii) fixed firm Export Interchange Transactions that cleared in the Day-Ahead Market plus (iii) 90% of its Reported Load is in compliance with the must-offer requirement for that Asset Owner and will not be assessed a must-offer penalty for that Asset Owner for that hour of the Operating Day.

(c) A Market Participant that does not offer Resources as described in (a) or (b) above, but the sum of its (i) offered Resources plus (ii) Firm Power Purchases less Firm Power Sales plus (iii) Real-Time purchase power agreement obligations, for that Asset Owner for that hour, is greater than or equal to the sum of its (i) Operating Reserve obligation plus (ii) fixed Export Interchange Transactions that cleared in the Day-Ahead Market plus (iii) 90% of its Reported Load is in compliance with the must-offer requirement for that Asset Owner for that hour and will not be assessed a must-offer penalty for that Asset Owner for that hour of the Operating Day.

(d) A Market Participant that does not offer sufficient Resources as described in (1) or (2)(a) through (2)(c) above is not in compliance with the must-offer requirement and will be assessed a must-offer penalty for that Asset Owner for that hour of the Operating Day as described in Section 4.2.1.1.1.

A Market Participant’s load for purposes of this section shall be equal to the Market Participant’s maximum hourly Reported Load excluding any GFA Carve-Out Schedules for the Operating Day.

A Market Participant’s daily Operating Reserve obligation shall be equal to the sum of that Market Participant’s maximum daily Regulation-Up, Regulation-Down and Contingency Reserve obligation as calculated by SPP as described in Section 4.1.2.3(3).

Only Resources submitted with a Commitment Status of Market or Self may be used to satisfy this requirement.
A Market Participant’s net resource capacity, for purposes of this section shall include:

Offered capacity by Resources identified in 4.2.1.1(3) less the Operating Reserve obligation identified in 4.2.1.1(2); and

Firm Power purchases less the Firm Power sales.

Market Participants with net resource capacity, as determined in Section 4.2.1.1(4), less than 90% of the Market Participant’s maximum hourly Reported Load excluding any GFA Carve Out Schedules for the Operating Day shall be deemed resource deficient and may be subject to sanctions as determined in Section 8.2.7.1.

Resources used as the source of a GFA Carve Out must be offered, if available, with a sufficient capacity to cover the GFA Carve Out Schedule. GFA Carve Out treatment is only available to the extent that the Resources are offered into the DA Market using a commit treatment of “Market” or “Self.” To the extent the source is external, an Import Interchange Transaction must be submitted in the DA Market with a sufficient capacity to cover the GFA Carve Out Schedule.

### 4.2.1.1 Penalty Calculation

For each hour that a Market Participant is found to be non-compliant as determined by the conditions set forth in Sections 4.2.1.1, the Market Participant shall be assessed a penalty for each non-compliant Asset Owner for each not offered megawatt as calculated below in excess of the 10% tolerance band. The penalty amount and the distribution of penalty revenues shall be determined as follows:

1. An Asset Owner’s penalty amount in each hour is calculated by multiplying the Asset Owner Must-Offer Penalty MW by the maximum of zero or the Must-Offer Penalty LMP for that hour.

   a. An Asset Owner Must-Offer Penalty MW is equal to the minimum of (i) the Asset Owner Shortage MW or (ii) the Asset Owner Not Offered MW:

      i. An Asset Owner Shortage MW is calculated as the difference between:

         1. The sum of (i) Asset Owner Operating Reserve obligation plus (ii) fixed firm Export Interchange Transactions plus (iii) Firm Power Sales plus (iv) 90% of its Reported Load for that hour; and

         2. The Asset Owner offered MWs.
(ii) An Asset Owner Not Offered MW is calculated as the maximum of zero (0) MWs or:

(1) The reference levels for the Maximum Economic Capability Operating Limit, as determined by the process in Section 8.2.2.7, less derate MW amounts approved and recorded in the outage scheduler tool for the Asset Owner’s Resources, excluding VERs and Demand Response Resources, with Commitment Status = ‘Reliability’ or ‘Not Participating’; minus

(2) Firm Power Purchases as described in Section 4.2.1.1; minus

(3) Real-Time purchase power agreement obligations as described in Section 4.2.1.1;

(b) The Must-Offer Penalty LMP is calculated as the difference between the weighted average of the Day-Ahead LMP minus the hourly, weighted average Real-Time LMP for the Asset Owner Resources, where the weights for the calculation are the corresponding Not Offered MWs;

In any hour in which must-offer penalty revenues are collected, compliant Asset Owners will receive a pro-rata share of such revenues. The pro-rata share shall be equal to the ratio of each compliant Asset Owner Reported Load for the hour to the sum of all compliant Asset Owner Reported Loads for that hour.

4.5.11 Miscellaneous Amount

(1) In certain circumstances, it may be necessary to recalculate or make changes to previously billed charges that cannot be handled though a standard final settlement or resettlement execution for that operating day. This is anticipated to occur only on an exception basis. SPP will manually calculate the adjustment and post as a manual adjustment to the appropriate final or resettlement statement for the Operating Day in question. SPP will post supporting documentation for the manual calculation of any miscellaneous charge to the Portal no later than the time the Settlement Statement including the miscellaneous charge has been posted. In some situations the charge or credit assessed must be excluded from Revenue Neutrality Uplift calculations such that SPP is left with a net receivable or payable amount for the settlement of the OD.

(2) In addition, through Balancing Authority Agreements with adjacent external Balancing Authorities, SPP may supply Emergency Export Interchange Transactions when
requested by the applicable external Balancing Authority or SPP may request, under SPP Emergency conditions, that applicable external Balancing Authorities supply Emergency Import Interchange Transactions to SPP. To the extent that such transactions are confirmed, credits to SPP for Emergency Export Interchange Transactions and charges to SPP for Emergency Import Interchange Transactions are included in this charge type.

(3) In addition, a local transmission operator may require commitment, decommitment, or dispatch instructions to be issued to one or more Resources in order to solve a reliability issue. Payments to Resource Asset Owners as described under Sections Error! Reference source not found., Error! Reference source not found. and charges to Asset Owners as described under Section Error! Reference source not found. associated with such commitment, decommitment, or dispatch instructions are included in this charge type.

(4) In addition, SPP may impose penalties for noncompliance with the Day-Ahead Market must-offer requirement as described under Section 4.2.1.1.1. Any penalties assessed to noncompliant Asset Owners, and the distribution of those penalties by load-ratio share, excluding the noncompliant Asset Owners, are included in this charge type.

(5) A miscellaneous charge type will be utilized for each distinct charge type and any other charges and credits not specifically accounted for under a distinct charge type. Miscellaneous charges and credits to the affected Asset Owners are represented for each Operating Day as follows:

\[
\text{MiscDlyAmt}_{a, ct, s, rnu, d}
\]

For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The net daily amount is calculated as follows:

\[
\text{MiscAoAmt}_{a, m, d} = \sum_{ct} \sum_{s} \sum_{rnu} \text{MiscDlyAmt}_{a, ct, s, rnu, d}
\]

(6) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{MiscMpAmt}_{m, d} = \sum_{a} \text{MiscAoAmt}_{a, m, d}
\]
The above variable is defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>MiscDlyAmt $a, ct, s, rnu, d$</td>
<td>$</td>
<td>Operating Day</td>
<td>Miscellaneous Amount per AO per Settlement Location per Operating Day – The miscellaneous amount to AO $a$ for charge type $ct$ at Settlement Location $s$ in Operating Day $d$.</td>
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<tr>
<td>MiscAoAmt $a, m, d$</td>
<td>$</td>
<td>Operating Day</td>
<td>Miscellaneous Amount per AO per Operating Day – The total miscellaneous amount to AO $a$ in Operating Day $d$.</td>
</tr>
<tr>
<td>MiscMpAmt $m, d$</td>
<td>$</td>
<td>Operating Day</td>
<td>Miscellaneous Amount per MP per Operating Day – The total miscellaneous amount to MP $m$ in Operating Day $d$.</td>
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<tr>
<td>$Ct$</td>
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<td>none</td>
<td>Any charge type specified under Sections Error! Reference source not found., Error! Reference source not found. or Error! Reference source not found. or any other miscellaneous charges not specifically accounted for under a distinct charge type.</td>
</tr>
<tr>
<td>$S$</td>
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<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>$Rnu$</td>
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<td>none</td>
<td>A flag which instructs the settlement system to include the amount in Revenue Neutrality Uplift calculations ($1 = Y, 0 = N$).</td>
</tr>
<tr>
<td>$D$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
</tbody>
</table>
8.1.4.2 Monitoring Activities

The Market Monitor will implement the market monitoring protocols and will monitor SPP’s Markets and Services by reviewing and analyzing market data and information including, but not limited to:

1. Resource Registration data required under Section 6;

2. Resource Offer data and other Resource offer parameters required for use in either the DA Market or RTBM;

3. Demand Bids for the purchase of Energy in the DA Market;

4. Virtual Energy Bids and Offers for the purchase or sale of Energy in the DA Market;

5. Export Interchange Transaction Bids and Import Interchange Transaction Offers for the purchase or sale of Energy in the DA Market or RTBM;

6. Actual commitment and dispatch of Resources, including but not limited to Resource MW capability and output, MVAR capability and output, status, and outages;

7. Additional generation and transmission facility outage data not otherwise provided for in (6) above; [MCRR36.6]

8. Locational Marginal Prices and Market Clearing Prices at all nodes and designated Settlement Areas in or affecting any of the SPP Markets and Services;

9. SPP Balancing Authority Area data, including but not limited to demand, area control error, net scheduled interchange, actual total net interchange, and forecasts of operating reserves and peak demand;

10. Conditions or events both inside and outside the SPP Balancing Authority Area affecting the supply and demand for, and the quantity and price of, products or services sold or to be sold in the SPP Markets and Services;

11. Information regarding transmission services and rights, including the estimating and posting of Available Transfer Capability (“ATC”) or Available Flowgate Capability (“AFC”), administration of SPP’s tariff, the operation and maintenance of the transmission system, any auctions or other markets for transmission rights, and the reservation and scheduling of transmission service;

12. Information regarding the nature and extent of transmission congestion in the region and, to the extent practicable, transmission congestion on any other system that affects the SPP Markets and Services, including but not limited to causes of, costs of and charges for transmission congestion, transmission facility loading, MVA capability, line status and outages;

13. Settlement data for the SPP Markets and Services;
Any information regarding collusive or other anticompetitive or inefficient behavior in or affecting any of the SPP Markets and Services;

Generation resource operating cost data for estimating Resource incremental cost, including fuel input costs, heat rates where applicable, start-up fuel requirements, environmental costs and variable operating and maintenance expenses; and

Logs of Transmission Service requests and Generation Interconnection requests along with the disposition of the request and the explanation of any refused requests; and

(17) Ramp reservation usage; and

Any manipulative behavior associated with Day-Ahead Offers, any locational problems, such as deliverability issues, associated with load-serving Market Participants’ Offers in the Day-Ahead market, any identified efforts by Market Participants to raise prices in the RTBM by limiting Day-Ahead Offers, and the effects of any such efforts upon make whole payments.

In addition to the monitoring of market data and information, the Market Monitor may communicate with SPP Staff and Market Participants at any time for the purpose of monitoring and assessing market conditions.

8.2.7 Sanctions for Noncompliance with the Day-Ahead Market Must Offer Requirement

A Market Participant is determined to be noncompliant with the Day-Ahead Market Must Offer requirement under the following circumstances:

(1) The Market Participant is resource deficient within the meaning of Section 4.2.1.1(5); and

(2) As a consequence of the resource deficiency impacts on LMPs, MCPs, and/or Make-Whole Payments, the Market Impact Test thresholds in Section 8.2.2.8 are determined by the Market Monitor to be exceeded; and

(3) The Market Monitor determines that the total production costs of the market would be reduced if the Market Participant had offered the Resource.

8.2.7.1 Penalty Calculation

In the case that a Market Participant is found to be noncompliant as determined by the conditions set forth in Sections 8.2.6.1(1) through 8.2.6.1(3) above, the Market Participant shall be assessed a penalty for each megawatt of withheld capacity below the 10% tolerance band. The penalty amount shall be equal to the Day-Ahead Market LMP associated with the withheld capacity.

The Market Monitor will monitor for, and report to the Commission’s Office of Enforcement (“OE”), manipulative behavior associated with Day-Ahead Offers including (but not limited to) monitoring load-serving Market Participants who purposefully underestimate peak loads. The Market Monitor will also report to OE any locational problems, such as deliverability issues, associated with load-serving Market Participants’ offers in the Day-Ahead market, any identified efforts by Market Participants to raise prices in the RTBM by limiting Day-Ahead Offers, and the effects of any such efforts upon make whole payments.
Participants to raise prices in the real-time market by limiting Day-Ahead offers, and the effects of any such efforts upon make whole payments.

Proposed Tariff Language Revision

Attachment AE

2.11.1 Day-Ahead Market

A. Each Market Participant must offer sufficient Resources to the Day-Ahead Market in accordance with this Section 2.11.1. to cover its Asset Owner’s individual load plus Operating Reserve obligation to the extent its Resources are available.

A. For the must-offer requirement, in order for a Resource to be considered offered, it must have a commitment status indicating either that the Market Participant is self-committing the Resource or that the Resource may be committed by the Transmission Provider, as specified in Section 4.1(10)(a) and (b) of the Attachment AE. Variable Energy Resources, Demand Response Resources and Resources with a commitment status indicating that the Resource is on outage, as specified in Section 4.1(10)(d) of this Attachment AE, are not required to be offered.

B. For the purposes of this Section 2.11.1, A Market Participant’s Operating Reserve obligation for an Asset Owner shall be equal to the sum of that Market Participant’s Regulation-Up and Contingency Reserve obligations for that Asset Owner as estimated by the Transmission Provider in accordance with Section 3.1.4(3) of this Attachment AE.

C. For purposes of this Section 2.11.1 of this Attachment AE, firm power purchases and firm power sales shall mean sales and purchases that are deliverable with transmission service comparable to Firm Point-To-Point Transmission Service or Firm Network Integration Transmission Service and the capacity and energy is supplied under standards of reliability and availability equivalent to supply of native load customers with the supplier assuming the obligation to provide both capacity and energy. Additionally, firm power purchases shall include an Asset Owner’s share of a Jointly Owned Unit to the extent that such shares have not been registered as individual Resources either under the JOU Individual Resource Option or the JOU Combined Resource Option as described under Section 2.2(4) of this Attachment AE. Supporting documentation for firm power purchases and firm power sales must be provided to the Market Monitor upon request.
D. For the purposes of this Section 2.11.1, Real-Time purchase power agreement obligations shall mean contractual commitments by an Asset Owner to make firm Energy available in Real-Time. Supporting documentation for Real-Time purchase power agreement obligations must be provided to the Market Monitor when requested.

E. If a Market Participant is compliant with the must offer requirement described in Section 2.11.1.F for an Asset Owner for an hour, the Market Participant will not be assessed a must offer penalty for that Asset Owner for that hour in the Operating Day.

F. Must Offer Requirement Process

(1) If the Day-Ahead Market clears for an hour of the Operating Day without executing the procedures described in Section 5.1.2(1)(a)(i) of this Attachment AE, then the Day-Ahead Market will be deemed Resource-sufficient for that hour, and no must-offer requirement penalties will be assessed for that hour.

(2) If the Day-Ahead Market does not clear as described in (1) above:

(a) A Market Participant that offers all Resources as described in Section 2.11.1.A above in this section, for an Asset Owner for that hour is in compliance with the must-offer requirement for that Asset Owner for that hour of the Operating Day, and will not be assessed a must-offer requirement penalty for that Asset Owner for that hour of the Operating Day.

(b) A Market Participant that does not offer all an Asset Owner’s Resources as described in (a) above, but offers Resources, for an Asset Owner for that hour, that is are greater than or equal to the sum of (i) the Asset Owner’s Operating Reserve obligation plus (ii) the Asset Owner’s fixed firm Export Interchange Transactions that cleared in the Day-Ahead Market plus (iii) 90% of the Asset Owner’s Reported Load, is in compliance with the must-offer requirement for that Asset Owner and will not be assessed a must-offer requirement penalty for that Asset Owner for that hour of the Operating Day.

(c) A Market Participant that does not offer an Asset Owner’s Resources as described in (a) or (b) above, but the sum of its (i) such Asset Owner’s generation offered Resources andplus (ii) such Asset Owner’s firm power purchases less firm power sales andplus (iii) such Asset Owner’s Real-Time purchase power agreement obligations, for an Asset Owner for that hour, is greater than or
equal to the sum of (i) such Asset Owner’s Operating Reserve obligation plus (ii) such Asset Owner’s fixed firm Export Interchange Transactions that cleared in the Day-Ahead Market plus (iii) 90% of such Asset Owner’s Reported Load, is in compliance with the must-offer requirement and will not be assessed a must-offer requirement penalty for that Asset Owner for that hour of the Operating Day.

(d) A Market Participant that does not offer sufficient Resources for an Asset Owner as described in subsections (1) or (2)(a) through (2)(c) above is in compliance with the must-offer requirement and will be assessed a must-offer requirement penalty for that Asset Owner for that hour of the Operating Day as described in Section 2.11.1.1 of this Attachment AE.

(1) A Market Participant’s load for purposes of this section shall be equal to that Market Participant’s maximum hourly Reported Load for the Operating Day.

(2) A Market Participant’s daily Operating Reserve obligation shall be equal to the sum of that Market Participant’s maximum daily Regulation-Up, Regulation-Down and Contingency Reserve obligations as estimated by the Transmission Provider in accordance with Section 3.1.4(3) of this Attachment AE.

(3) A Market Participant may satisfy this requirement only by offering Resources with a commitment status indicating either that the Market Participant is self-committing the Resource or that the Resource may be committed by the Transmission Provider, as specified in Section 4.1.10(a) and (b) of the Attachment AE.

(4) A Market Participant’s net resource capacity, for purposes of this section shall include:
   i. Offered capacity by Resources identified in Section 2.11.1.A(3) of Attachment AE less the Operating Reserve obligation identified in Section 2.11.1.A(2) of Attachment AE; and
   ii. Firm power purchases less firm power sales. For purposes of this Section 2.11.1 of this Attachment AE firm power purchases and firm power sales shall mean sales and purchases that are deliverable with transmission service comparable to Firm Point To Point Transmission Service or Firm Network Integration Transmission Service and the capacity and energy is supplied under standards of reliability and availability equivalent to supply of native load customers with the supplier assuming the obligation to provide both capacity and energy.
B. Market Monitor shall monitor offered Resources, self-committed Resources, firm power purchases, firm power sales, and Reported Load for the Operating Day.

(1) Market Participants who have offered and/or self-committed 100% of their net resource capacity, as determined in Section 2.11.1.A(4) of this Attachment AE, are deemed to be in compliance with the must offer requirement.

(2) Market Participants who have offered and/or self-committed less than 100% of their net resource capacity, as determined in Section 2.11.1.A(4) of this Attachment AE, and less than 90% of the Market Participant’s maximum hourly Reported Load for the Operating Day shall be deemed resource deficient and may be subject to sanctions as determined in Attachment AF, Section 3.9 of this Tariff.

2.11.1 Must-Offer Penalty Calculation

For each hour that a Market Participant is found to be noncompliant as determined by the conditions set forth in Section 2.11.1 of this Attachment AE, the Market Participant shall be assessed a penalty by the Transmission Provider. Such penalty shall be assessed for each noncompliant Asset Owner for each hour in which the Market Participant is noncompliant by the Transmission Provider, for each Asset Owner Must-Offer Penalty MW not offered as calculated below— in excess of the 10% tolerance band. The penalty amount and distribution of penalty revenues shall be determined as follows:

(1) The penalty amount for an Asset Owner in each hour is calculated by multiplying the Asset Owner Must-Offer Penalty MW by the maximum of zero or the Must-Offer Penalty LMP for that hour, whichever is greater.

(a) Asset Owner Must-Offer Penalty MW is equal to the minimum of (i) the Asset Owner Shortage MW or (ii) the Asset Owner Not Offered MW;

(i) Asset Owner Shortage MW is calculated as the difference between:

(1) The sum of (i) Asset Owner Operating Reserve obligation plus (ii) Asset Owner fixed firm Export Interchange Transactions plus (iii) Asset Owner firm power sales plus (iv) 90% of Asset Owner Reported Load for that hour, as described under Section 2.11.1 of this Attachment AE; and

(2) The Asset Owner offered MWs, as described in Section 2.11.1.A of this Attachment AE.
(ii) Asset Owner Not Offered MW is calculated as the maximum greater of zero (0) MWs or:

(1) The sum of the reference levels for the Maximum Economic Capability Operating Limit, as determined by the process in Section 3.6 of Attachment AF, less any derated MW amounts approved and recorded in the outage scheduler tool for the Asset Owner Resources, excluding Variable Energy Resources and Demand Response Resources, with a commitment status indicating that the Resource may be committed for reliability issues as described in Section 4.1(10)(c) of this Attachment AE or that the Resource is not participating in the Day-Ahead Market as described in Section 4.1(10)(e) of this Attachment AE; minus

(2) Firm power purchases as described in Section 2.11.1.C of this Attachment AE; minus

(3) Real-Time power purchase agreement obligations as described in Section 2.11.1.D of this Attachment AE.

(b) The Must-Offer Penalty LMP is calculated as the difference between the weighted average of the Day-Ahead LMP minus the hourly, weighted average Real-Time LMP for the Asset Owner Resources with a commitment status as described in Section 4.1(10)(c) or 4.1(10)(e) of this Attachment AE, where the weights for the calculation are the corresponding Not Offered MWs.

(2) In any hour in which must offer penalty revenues are collected, from noncompliant Asset Owners, such revenues shall be distributed to Market Participants on a pro-rata basis for their Asset Owner(s) whose Resources were offered in compliance with the must offer requirement in Section 2.11.1 Asset Owners will receive a pro-rata share of such revenues. The pro-rata share shall be equal to the ratio of (i) each compliant Asset Owner Reported Load for the hour to (ii) the sum of all compliant Asset Owner Reported Loads for the hour.

3.1.4 Operating Reserve Requirements

The Transmission Provider shall calculate the amount of Operating Reserves required for the Operating Day, on both a system-wide and Reserve Zone basis, in order to comply with the
reliability requirements specified in the SPP Criteria. The Transmission Provider shall, on a daily basis:

(1) Calculate the hourly Regulation-Up, Regulation-Down and Contingency Reserve requirements on an SPP Balancing Authority Area basis and post such results by 0700 hours Day-Ahead for use in the Day-Ahead Market, Day-Ahead RUC, Intra-Day RUC and RTBM;

(2) Calculate the total minimum and total maximum Operating Reserve requirement for Operating Reserve deployment in the up direction and for deployment of Operating Reserve in the down direction for each Reserve Zone. *These minimum and maximum Operating Reserve requirements will be determined by conducting a simulated energy transfer study for each hour of the Operating Day on the transmission system, reflecting expected outages and economic energy flows, in order to determine the energy transfer limitations into or out of a Reserve Zone in any hour. If a Reserve Zone is unable to import enough Energy after a contingency and still maintain all necessary operating limits, a minimum amount of Operating Reserve may be required to be carried in that Zone. The minimum Operating Reserve requirement is the largest difference between the Resource MW lost in the simulated contingency and the resulting import capability of that Reserve Zone. Similarly, if a Reserve Zone is unable to export additional Energy after a contingency outside of that Reserve Zone, then a maximum amount of Operating Reserve that is deliverable from that Zone will be specified in order to ensure that deliverable reserves are carried in other Zones. The maximum Operating Reserve limitation is equal to the export capability of that Reserve Zone when replacing Energy lost due to a Resource contingency outside of that Reserve Zone.* The Transmission Provider may, at its option, set specific Regulation-Up and/or Spinning Reserve minimum requirements for each Reserve Zone, as needed, to address reliability issues that can only be alleviated through carrying synchronized reserves. In such cases, the Transmission Provider will include these minimum Regulation-Up and/or Spinning Reserve requirements when posting the Operating Reserve requirements by 0700 Day-Ahead;

(3) Estimate each Market Participant’s Operating Reserve obligation by Asset Owner in each Reserve Zone and provide such information to Market Participants by 0700 hours Day-Ahead. The Transmission Provider shall calculate such estimates by multiplying the system-wide Operating Reserve requirements calculated in (1) above by the Transmission
Provider’s estimate of each Market Participant’s Asset Owner’s load in each Reserve Zone divided by the Transmission Provider’s estimate of system-wide load; and

(4) The Transmission Provider may increase Operating Reserve requirements for the Day-Ahead RUC, Intra-Day RUC and RTBM above the requirements used in the Day-Ahead Market, including changes to Reserve Zone minimums and maximums, as required to meet increases in reliability requirements caused by changes in system conditions.

Attachment AF

3.9—Sanctions for Noncompliance with the Day-Ahead Market Must Offer Requirement

A. A Market Participant is determined to be noncompliant with the Day-Ahead Market must offer requirement under the following circumstances:

(1) The Market Participant is resource deficient within the meaning of Attachment AE, Section 2.11.1.B(1) of this Tariff;

(2) As a consequence of the resource deficiency impacts on LMPs, MCPs, and/or make whole payments, the Market Impact Test thresholds in Section 3.7 of this Attachment AF are determined by the Market Monitor to be exceeded; and

(3) The Market Monitor determines that the total production costs of the market would be reduced if the Market Participant had offered the Resource.

B. In the case that a Market Participant is found to be noncompliant as determined by the conditions set forth in Sections 3.9.A(1) through 3.9.A(3) of this Attachment AF, the Market Participant shall be assessed a penalty by the Transmission Provider for each megawatt of withheld capacity below the 10% tolerance band. The penalty amount shall be equal to the Day-Ahead Market LMP associated with the withheld capacity.

C. The Market Monitor will monitor for, and report to the Commission’s Office of Enforcement, or its successor organization, manipulative behavior associated with Day-Ahead Offers, including (but not limited to) monitoring load-serving Market Participants who do not offer enough net resource capacity to meet their maximum hourly Reported Load. The Market Monitor will also report to the Commission’s Office of Enforcement or its successor organization any locational problems, such as deliverability issues, associated with load-serving Market Participants’ offers in the Day-Ahead Market, any identified efforts by Market Participants to raise prices in the RTBM by limiting Day-Ahead Offers, and the effects of any such efforts upon make whole payments.
4.2 Market Monitoring Scope

The Market Monitor will implement the Plan. The markets will require continuous monitoring by the Market Monitor. The Market Monitor will monitor Markets and Services by reviewing and analyzing market data and information including, but not limited to:

(a) Resource registration data;
(b) Resource Offer data including non-price related offer parameters required for use in either the Day-Ahead Market, Reliability Unit Commitment process and/or Real-Time Balancing Market;
(c) Demand Bids for the purchase of Energy in the Day-Ahead Market;
(e) Export Interchange Transaction Bids and Import Interchange Transaction Offers for the purchase and sale of Energy in the Day-Ahead Market and the Real-Time Balancing Market;
(f) Actual commitment and dispatch of Resources, including but not limited to Resource MW capability and output, MVAR capability and output, status, and outages;
(g) Locational Marginal Prices and zonal Market Clearing Prices at all Settlement Locations in or affecting any of Markets and Services;
(h) SPP Balancing Authority Area data, including but not limited to demand, area control error, Net Scheduled Interchange, actual total net interchange, and forecasts of operating reserves and peak demand;
(i) Conditions or events both inside and outside the SPP Balancing Authority Area affecting the supply and demand for, and the quantity and price of, products or services sold or to be sold in Markets and Services;
(j) Information regarding transmission services and rights, including the estimating and posting of Available Transfer Capability (“ATC”) or Available Flowgate Capability (“AFC”), administration of this Tariff, the operation and maintenance of the transmission system, any auctions or other markets for transmission rights, and the reservation and scheduling of transmission service;
(k) Information regarding the nature and extent of transmission congestion in the region and, to the extent practicable, transmission congestion on any other system that affects Markets and Services, including but not limited to causes of, costs of and charges for transmission congestion, transmission facility loading, MVA capability, line status and outages;

(l) Settlement data for the Markets and Services;

(m) Any information regarding collusive or other anticompetitive or inefficient behavior in or affecting any of Markets and Services; and

(n) Generation resource operating cost data for estimating resource incremental cost, including fuel input costs, heat rates where applicable, start-up fuel requirements, environmental costs and variable operating and maintenance expenses.

(o) Logs of transmission service requests and Generation Interconnection Requests along with the disposition of each request and the explanation of any refused requests;

(p) Any additional Resource and transmission facility outage data not otherwise provided for in this Section 4.2;

(r) GFA Carve Out Schedules and

(s) Any manipulative behavior associated with Day-Ahead Offers, any locational problems, such as deliverability issues associated with load-serving Market Participants’ Offers in the Day-Ahead market, and any efforts by Market Participants to raise prices in the RTBM by limiting Day-Ahead Offers as well as the effects of any such efforts upon make whole payments.

Proposed Criteria Language Revision

N/A
### PRR Recommendation Report

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<th>PRR No.</th>
<th>Marketplace-PRR145</th>
<th>PRR Title</th>
<th>Head-room &amp; Floor-room Capacity Requirements</th>
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#### Timeline

- [x] Normal
- [ ] Expedited
- [ ] Urgent Action

Provide explanation if Expedited and/or Urgent Action is selected:

#### Recommendation Action

- [x] Approve
- [ ] Reject
- [ ] Require additional information
- [ ] Defer
- [ ] Refer

#### Impact Analysis Required

- [ ] Yes – If yes, estimated cost:  
  - [x] No

  **SPP Staff will complete this section.**

#### Protocol Section(s) Requiring Revision

**Section No.:** 1, 4.1.3, 4.1.3.2, 4.1.3.2.1, 4.1.3.2.2, 4.3.1.1, 4.3.1.2, 4.3.2.1, 4.3.2.2, 4.4.1.1, 4.4.1.2.


**Protocol Version:** 15.0a

#### Type of Revision

- [ ] Correction/Clean-Up
- [x] Clarification
- [ ] Design Enhancement
- [ ] Design Change

#### Timeline

- [x] Go-Live
- [ ] Post Go-Live

#### Revision Description

Transparency is needed regarding the reasoning behind Head-room unit commitments as these unit commitments create a financial impact to Market Participants in the form of potential increases to Day-Ahead Market and/or RUC Make-Whole Payments.

#### Tariff Implications or Changes

- [x] Yes – Section No: *(Include a summary of impact and/or specific changes)*
  - 1.1 - Definitions, 3.1.4 – Operating Reserve, Head-room and Floor-room Requirements, 5.1.1 - Day-Ahead Market Inputs, 5.1.2 - Day-Ahead Market Execution, 5.2.1 - Day-Ahead Reliability Unit Commitment Inputs, 5.2.2 - Day-Ahead Reliability Unit Commitment Execution, 6.1.1 – Intra-Day Reliability Unit Commitment Inputs, 6.1.2 – Intra-Day Reliability Unit Commitment Execution.
  - No

#### Criteria Impact or Changes

- [ ] Yes – Section No: *(Include a summary of impact and/or specific changes)*
  - No

#### MWG Review PRR Recommendation

- **Date of Vote:** 9/18/2013
- **Vote:** Approved
- **Opposed:** AEP, Xcel, GSEC
- **Abstained:** Tri-County, OGE

#### RTWG Review

- **Date of Vote:** 9/25/2013
- **Vote:** Approved with modifications
### ORWG Review

**Date of Vote:** 10/1/2013  
**Vote:** Approved

### MOPC Recommendation

**Date of Vote:**  
**Vote:**

### Board Review

**Date of Vote:**  
**Vote:**

---

**Date**  
8/23/2013

#### Sponsor

**Name**  
Micha Bailey

**E-mail Address**  
mcbailey@spp.org

**Company**  
Southwest Power Pool

**Phone Number**  
501.688.2522

---

#### Reasons for Opposing

**Dissenter**  
Amber Metzker - Xcel

**Date**  
9/18/2013

**Reason**  
Due to this MPRR having a requirement for this to occur in the day ahead commit process.

---

#### Comments Received

**Comment Author**  
Ron Gunderson - NPPD

**Date**  
8/27/2013

**Comment Description**  
Head-room and floor-room requirements should be based upon more than just the difference between load at the beginning or end of an hour and the average load for the hour. Load forecasts and wind forecasts are not 100% accurate, especially in the day ahead timeframe and head-room and floor-room should include those load and generation uncertainties to be sure the market has adequate capacity committed or de-committed to ensure units can be dispatched within their operating ranges in the event load is higher or lower than expected.

Descriptions of the SCUC do not consistently treat Import Interchange Transactions and proposed changes are identified below to make the language more consistent and reflective of what actually is being done.

Section 3.1.4 of the tariff has a sentence that does not flow well.

**Comment Status**  
The approved language is reflected in this recommendation report.

---

#### Comments Received

**Comment Author**  
Micha Bailey – Southwest Power Pool

**Date**  
8/27/2013

**Comment Description**  
SPP added language that would allow SPP the option to reduce the Head-room and the Floor-room requirements calculated down to zero in the Day-Ahead Market. This process improvement would help SPP to make sure that there was not an over commitment of Resources in the Day-Ahead Market.

**Comment Status**  
The approved language is reflected in this recommendation report.

---

#### Comments Received

**Comment Author**  
Micha Bailey – On behalf of the MWG

**Date**  
9/18/2013

**Comment Description**  
MWG gave SPP staff the task in the motion to amend the language. The amended language will allow clearing of 50% of the hourly Real-Time expected Head-room and Floor-room needs in the Day-Ahead Market, and will include conforming Tariff changes. MWG also add, "The Head-room and Floor-room requirements will be reviewed by the Market Working Group quarterly…” to allow the MWG to review
and provided feedback for the Head-room and Floor-room requirement.

**Comment Status**
The approved language is reflected in this recommendation report.

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**Proposed Protocol Language Revision**

1. **Glossary**

   **Head-room**

   As defined in the SPP Tariff.

   **Floor-room**

   As defined in the SPP Tariff.

4.1.3 **Operating Reserve, Head-room and Floor-room Requirements**

SPP calculates the amount of Operating Reserve required for the Operating Day, on both a system-wide basis and a Reserve Zone basis, to comply with the reliability requirements specified in the SPP Criteria. Additionally, SPP calculates the amount of Head-room and Floor-room required for the Operating Day to ensure that unit commitment is sufficient to reliably serve load in real-time while maintaining the Operating Reserve requirements. SPP calculates the hourly Regulation-Up, Regulation-Down, and Contingency Reserve, Head-room and Floor-room requirements on an SPP BAA basis and calculates minimum Operating Reserve requirements and maximum Operating Reserve limitations for each Reserve Zone.

(1) SPP BAA Contingency Reserve requirements are set consistent with SPP Criteria and may vary on an hourly basis.

(2) SPP BAA Regulation-Up and Regulation-Down requirements are set to ensure compliance with NERC control performance requirements and are based upon a percentage of forecasted load, adjusted up or down to account for resource output variability, and may vary on an hourly basis.

(2)(3) SPP BAA Head-room and Floor-room requirements are set to ensure that expected variations between real-time instantaneous load and the average load and variations between
The SPP BAA requirements, minimum Reserve Zone Operating Reserve requirements and maximum Reserve Zone Operating Reserve limitations are calculated and posted no later than 7:00 AM Day-Ahead. At this time, SPP will also communicate each Market Participant’s estimated Operating Reserve obligations in each Reserve Zone using the BAA Mid-Term Load Forecast and the Market Participant load forecasts developed by SPP under Section 4.1.2.1.5.

These Operating Reserve requirements and limitations are used by SPP as inputs into the DA Market and RTBM clearing and RUC processes.

SPP may increase Operating Reserve requirements for use in RTBM clearing and RUC processes above the requirements used in the DA Market clearing, including changes to Reserve Zone minimums and maximums, as required to meet increases in reliability requirements caused by changes in system conditions.

Reserve Zone minimum Operating Reserve requirements and maximum Operating Reserve limitations are determined through reserve zone studies prior to the DA Market. Reserve zone studies are performed as described under Section 4.1.3.1.

4.1.3.1 Reserve Zone Requirements

Reserve Zone studies are performed on a daily basis to determine each Reserve Zone’s minimum and maximum Operating Reserve requirements. A base case is produced using RTBM Resource Offer data to produce a Resource commitment and dispatch with all applicable transmission constraints activated. Using this base case, Reserve Zone studies are performed as follows.

4.1.3.1.1 Minimum Reserve Zone Operating Reserve Requirements

Using this base case commitment and dispatch, the loss of the largest Resource is simulated for each Reserve Zone and the unused physical import capability is assessed. Operating Reserve being supplied to a Reserve Zone from outside of the SPP BA as described under Section 4.2.2.5.7 is included in this evaluation;

(1) Power Transfer Distribution Factor (PTDF) interface flowgates for the import/export study will use appropriate ratings that do not reflect additional protection for transmission contingencies.

(2) If unused physical import capability, including capability set aside to protect against instability, uncontrolled separation, or cascading outages equals or exceeds the largest Resource MW, then Reserve Zone minimum is equal to zero.

(3) If unused physical import capability, including capability set aside to protect against instability, uncontrolled separation, or cascading outages is less than the largest Resource MW, then the
Reserve Zone minimum Operating Reserve requirement is equal to the lesser of: 1) the difference between the largest Resource MW and unused physical import capability; or 2) the difference between the Reserve Zone load and physical import capability.

(4) The Reserve Zone minimum Operating Reserve requirement can be met through clearing of the most economic combination of Regulation-Up, Spinning Reserve and Supplemental Reserve that is available on Resources located within the Reserve Zone.

(a) SPP may set specific Regulation-Up and/or Spinning Reserve minimum requirements for each Reserve Zone, as needed, to address reliability issues that can only be alleviated through carrying synchronized reserves. In such cases, SPP will include these minimum Regulation-Up and/or Spinning Reserve requirements when posting the Operating Reserve requirements by 0700 Day-Ahead.

4.1.3.1.2 Maximum Reserve Zone Operating Reserve Limitations

Using the base case commitment and dispatch, simulate the loss of the largest Resource in one Reserve Zone and assess the export capability in remaining Reserve Zones. Operating Reserve being supplied to a Reserve Zone from outside of the SPP BA as described under Section 4.2.2.5.7 is included in this evaluation.

(1) Aggregate and proxy PTDF flowgates for the import/export study will use appropriate ratings that do not reflect additional protection for transmission contingencies.

(2) A Reserve Zone maximum Operating Reserve limitation would be equal to the incremental export capability of the Reserve Zone without violating any system operating limits. The Reserve Zone maximum Operating Reserve limitation can be met through clearing of the most economic combination of Regulation-Up, Spinning Reserve and Contingency Reserve that is available on Resources located within the Reserve Zone.

4.1.3.2 Head-room and Floor-room Requirements

For Day-Ahead Market and RUC which use hourly load granularity, intra-hour Head-room and Floor-room requirements represent the needed real-time online capacity to address load changes within the Operating Hour and variations between real-time variable resource output and projected variable resource output. For example, during morning load pickup, the end-of-hour capacity requirements may be much greater than the average hourly energy represented by the cleared demand in the Day-Ahead Market or the load forecast used in the RUC processes. Additionally, the load forecast or generation forecast for a variable resource can be off due to uncertainties inherent in these load and generation forecasts. If Resources were committed only for the average hourly load, the online capacity at the end of the morning load pickup hour may be insufficient to support reliable real time operations. SPP calculates the required Head-room and Floor-room requirements for both the Day-Ahead Market and the RUC processes as follows. SPP may include up to 0% of the calculated Head-room and Floor-room
requirements as an input into the Day-Ahead Market and may include 100% of the calculated Head-room and Floor-room requirements in all RUC processes.

4.1.3.2.1 Day-Ahead Market

SPP estimates the hourly Head-room and Floor-room requirements to be included in the Day-Ahead Market using SPP’s Mid-Term Load Forecast and expected real-time instantaneous load values for the Operating Day including a factor for load forecast and variable resource output uncertainty. SPP’s Mid-Term Load Forecast represents the expected average load in an Operating Hour. For Head-room and Floor-room requirement calculations, the instantaneous load is assumed to be equal to the expected average load at the midpoint of the Operating Hour and ramp linearly from this point to the expected average load at the midpoint of the neighboring Operating Hours. Because this assumption will not always be accurate, especially in Operating Hours in which an instantaneous peak load or an instantaneous minimum load trough occurs, and due to load forecast and variable resource output uncertainty, SPP requires an amount of Head-room and Floor-room requirements.

(1) The Head-room requirement for the current Operating Hour is set equal to the maximum of: (i) the difference between the expected instantaneous load at the beginning of the Operating Hour and expected average load in the Operating Hour; (ii) the difference between the expected instantaneous load at the end of the Operating Hour and the expected average load in the Operating Hour; or (iii) the minimum Head-room requirement. SPP may reduce the Head-room requirement calculated above as operational experience dictates and/or to account for differences between offered Day-Ahead Market Resources and those available in the RUC processes.

(2) The Floor-room requirement for the current Operating Hour is set equal to the maximum of: (i) the difference between the expected average load in the Operating Hour and the expected instantaneous load at the beginning of the Operating Hour; (ii) the difference between the expected average load in the Operating Hour and the expected instantaneous load at the end of the Operating Hour; or (iii) the minimum Floor-room requirement. SPP may reduce the Floor-room requirement calculated above as operational experience dictates and/or to account for differences between offered Day-Ahead Market Resources and those available in the RUC processes.

The expected instantaneous load at the beginning of the Operating Hour is estimated as the load forecast value at the point at which a straight line drawn from the midpoint of the previous Operating Hour’s expected average load to the midpoint of the current Operating Hour’s expected average load crosses the beginning of the current Operating Hour.

The expected instantaneous load at the end of the Operating Hour is estimated as the load forecast value at the point at which a straight line drawn from the midpoint of the current Operating Hour’s expected average load to the midpoint the next Operating Hour’s expected average load crosses the end of the current Operating Hour.
The minimum Head-room and Floor-room requirements will be determined by SPP based upon operating experience. The Head-room and Floor-room requirements will be reviewed by the Market Working Group quarterly and may be refined over time based upon the relationship between SPP Mid-Term Load Forecast average loads and observed instantaneous load values.

4.1.3.2.2 RUC

For all RUC processes, SPP estimates the hourly Head-room and Floor-room requirements to be included in the RUC analyses using the most current Mid-Term Load Forecast and expected real-time instantaneous load values for the Operating Day using the same methodology as described under Section 4.1.3.2.1 for the Day-Ahead Market.

4.3.1.1 DA Market Inputs

Inputs to the DA Market algorithm consist of:

1. DA Market Offers and Bids as submitted by Market Participants prior to 1100 hours Day-Ahead;
   
   a. For Demand Bids, Virtual Energy Bids and/or Virtual Energy Offers submitted at a Load Settlement Location that contains more than one PNode, SPP distributes the Bid MW down to the associated PNodes using weighting factors for modeling purposes as described under Section 4.1.2.1.6.
   
   b. For Virtual Energy Bids and/or Virtual Energy Offers submitted at a Market Hub Settlement Location and confirmed Interchange Transactions submitted at an External Interface, SPP uses a common set of weighting factors to distribute the Bid and/or Offer MWs down to PNodes included in the Market Hub or External Interface for modeling purposes. These weighting factors are determined by SPP at the time the Trading Hub or External Interface is created and are not dependent upon historical injections/withdrawals. Resource Hub weighting factors are determined by SPP after coordinating with the requesting Market Participant.

2. Resource Offers for long lead time Resources selected by SPP for commitment during the Operating Day during the Multi-Day Reliability Assessment process;

3. Through Interchange Transactions as submitted by Market Participants and confirmed prior to 1100 hours Day-Ahead;

4. SPP Operating Reserve requirements (system-wide and Reserve Zone min and max);
   
   5. SPP Head-room and Floor-room requirements;
   
   6. SPP Transmission System topology consistent with Network Model in place for current Operating Day, including adjustments to RCF firm flow entitlements if applicable;
   
   7. Transmission System outages;
Parallel Flow forecasts; and
Resource outages.

4.3.1.2 DA Market Execution

SPP clears the Day-Ahead Market for each hour of the upcoming Operating Day based on the inputs described above. A simultaneous co-optimization methodology, utilizing the SCUC and SCED algorithms is employed to simultaneously perform the following tasks:

1. Commit offered Resources, Import Interchange Transaction Offers and Virtual Energy Offers using the SCUC algorithm to meet the Demand Bids, Virtual Energy Bids, Export Interchange Transactions Bids, Head-room requirements, Floor-room requirements and Operating Reserve requirements at least cost throughout the projected upcoming Operating Day while respecting Resource operating constraints and transmission constraints;

   a. The DA Market SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market and Self, including Resources committed in the Multi-Day Reliability Assessment process, only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up) and down to the Resources Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down).

      i. If this capacity is not sufficient to meet the fixed Demand Bids, fixed Export Interchange Transaction Bids, Head-room requirements, Floor-room requirements, and Operating Reserve requirements on a system-wide basis, the DA Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limit and/or commit Resources’ with a Commit Status of Reliability on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

      ii. If there is a capacity surplus on a system-wide basis calculated as the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transaction Offers, Floor-room requirement and the Regulation-Down requirement that is in excess of the sum of Fixed Demand Bids and fixed Export Interchange Transaction Bids, the DA Market SCUC algorithm will, in priority order (1) curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limit on an economic basis until the capacity surplus is eliminated; (3) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limit on an economic basis until the capacity surplus is eliminated; and (4) operate Resources in accordance with the operating plan.
surplus is eliminated while attempting to maintain the Regulation-Down requirement to the extent possible.

(b) To the extent that a particular reliability issue cannot be directly addressed within the DA Market SCUC algorithm as described under subsection (i) and (ii) above, SPP may manually commit Resources to alleviate such reliability issues. SPP will re-run the DA Market SCUC algorithm after such manual commitments, time permitting, and will notify the Market Participants that units were manually committed. The SCED algorithm will be run based on the manual commitment to produce a final market solution.

4.3.2.1 Day-Ahead RUC Inputs

Inputs to the RUC algorithm consist of:

(1) RTBM Resource Offers, including Resources with a Self-Commit status submitted up to 1700 hours or one hour following the posting of the DA Market results, whichever is later;

a. During all hours between the start and completion of the Day-Ahead RUC process, Market Participants may continue to update RTBM Offers during Day-Ahead RUC process. If the DA RUC offer being updated is for the DA RUC Study Period, SPP will notify the Market Participant that the offer will not be used in the ongoing DA RUC solution.

(2) Confirmed cleared Export Interchange Transaction Bids from the DA Market;

(3) Confirmed cleared Import Interchange Transaction Offers from the DA Market;

(4) Confirmed cleared Through Interchange Transactions from the DA Market;

(5) Confirmed Export Interchange Transactions specified for use in the RTBM only;

(6) Confirmed Import Interchange Transactions specified for use in the RTBM only;

(7) Confirmed Through Interchange Transactions specified for use in the RTBM only;

(8) SPP Operating Reserve requirements (system-wide and Reserve Zone min and max);

(9) SPP Head-room and Floor-room requirements;

(10) SPP Mid-Term Load Forecast (MTLF) as described under Section 4.1.2.1;

(11) SPP Transmission System topology consistent with Network Model in place for the Operating Day, including adjustments to RCF firm flow entitlements if applicable;

(12) Resource commitment schedules from the DA Market unless SPP Operators are informed of a Resource outage;

(13) Commitment schedules for long lead time Resources selected in the Multi-Day Reliability Assessment process unless SPP Operators are informed of a Resource outage;

(14) Wind Resource MWh output forecast as described under Section 4.1.2.2;
Transmission System outages; Parallel Flow forecasts; and Resource outages.

4.3.2.2 Day-Ahead RUC Execution

Using the inputs described above, SPP performs a capacity adequacy analysis for the upcoming Operating Day using the SCUC algorithm. The capacity adequacy analysis provides advisory information to the SPP Operators.

1. The objective of the SCUC is to commit Resources to meet the SPP Mid-Term Load Forecast, Export Interchange Transactions, Head-room requirements, Floor-room requirements and Operating Reserve requirements less Import Interchange Transactions over the Operating Day such that commitment costs are minimized while adhering to transmission system security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers;

2. Commitment costs are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined in the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the RUC SCUC in making commitment decisions;

3. The SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market or Self only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up) and down to the Resources Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down).

   a. If this capacity plus Import Interchange Transactions is not sufficient to meet the system-wide SPP Mid-Term Load Forecast, Export Interchange Transactions, Head-room requirements plus Operating Reserve requirements, the SCUC algorithm study will, in priority order: (1) curtail non-firm Export Interchange Transactions until the capacity shortage is eliminated; (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limit and/or commit Resources’ with a Commit Status of Reliability on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

   b. If the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transactions, the Floor-room requirement Offers and the system-wide Regulation-Down requirement is in excess of the sum of the SPP system-wide Mid-Term Load Forecast and fixed Export Interchange Transactions, the RUC SCUC algorithm study will, in priority order: (1) curtail non-firm fixed Import Interchange Transactions until the capacity surplus is eliminated; (2) incorporate capacity down to Resources’ Minimum Emergency
Capacity Operating Limit on an economic basis until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement to the extent possible; (3) de-commit Resources that were committed in the DA Market with a Commit Status of Market until the capacity surplus in eliminated; and (4) de-commit Self-Committed Resources until the capacity surplus in eliminated.

(i) If there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, SCUC may commit additional Resources and/or de-commit Resources to relieve the constraints provided that any commitment changes do not aggravate the excess capacity situation.

(c) To the extent that a particular reliability issue cannot be directly addressed within the SCUC algorithm as described under subsection (a) and (b) above, SPP may manually commit Resources with a Commit Status of Reliability and de-commit Resources with a Commit Status of Self to alleviate such reliability issues in accordance with its authority as Reliability Coordinator.

*(i)* An Local Reliability Issue emergency condition may arise within the operating area of a local Transmission Operator that may involve elements not monitored by SPP. Such emergencies Local Reliability Issues may require out of merit commitment, decommitment or dispatch instructions to be issued to one or more Resources to resolve the Local Reliability Issue. In such cases, the local Transmission Operator shall request SPP to issue such instructions. To the extent that SPP commits a Resource to address a Local Reliability Issue at the request of a local transmission operator such Resource shall be eligible for compensation in the same manner as any other Resource. Recovery of such compensation shall be collected locally as described under Section 4.5.9.10. If the SPP determines that the instructions were required for regional reliability, recovery of such compensation shall be collected regionally as described under Section 4.5.9.10.

Any curtailment of schedules, use of Reliability Status Resources or use of Emergency operating limits by the RUC algorithms will only be advisory information to the SPP RUC Operators. Day-Ahead RUC and Intra-Day RUC Operators will determine which of these options should be acted on and when as described in the Day-Ahead and Intra-Day RUC Results sections.

### 4.4.1.1 Intra-Day RUC Inputs

Inputs to the RUC algorithm consist of:

1. RTBM Resource Offers;
2. Confirmed Export Interchange Transactions;
Confirmed Import Interchange Transactions;
Confirmed Through Interchange Transactions;

SPP Operating Reserve requirements (system-wide and Reserve Zone min and max);
SPP Head-room and Floor-room requirements;
SPP Mid-Term Load Forecast as described under Section 4.1.2.1;
SPP Transmission System topology consistent with Network Model in place for the Operating Day, including adjustments to RCF firm flow entitlements if applicable;
Resource commitment and de-commitment schedules from the Day-Ahead RUC or previous Intra-Day RUCs;
Wind Resource output forecast as described under Section 4.1.2.2;
Transmission System outages;
Parallel Flow forecasts; and
Resource outages.

4.4.1.2 Intra-Day RUC Execution

Using the inputs described above, SPP performs a capacity adequacy analysis for the upcoming Operating Day and throughout the Operating Day using a SCUC algorithm. The capacity adequacy analysis provides advisory information to the SPP Operators.

The objective of the SCUC is to commit Resources to meet the SPP Mid-Term Load Forecast, Export Interchange Transactions, Head-room requirements, Floor-room requirements and Operating Reserve requirements less Import Interchange Transactions over the Operating Day such that commitment costs are minimized while adhering to transmission system security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers;

Commitment costs are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined on the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the RUC SCUC in making commitment decisions;

The SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market or Self only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up) and down to the Resources Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down).
(a) If this capacity plus Import Interchange Transactions is not sufficient to meet the system-wide SPP Mid-Term Load Forecast, Export Interchange Transactions, Head-room requirements plus and Operating Reserve requirements, the SCUC algorithm study will, in priority order: (1) curtail non-firm Export Interchange Transactions until the capacity shortage is eliminated; (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limit and/or commit Resources’ with a Commit Status of Reliability on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

(b) If the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transactions, Floor-room requirements and the system-wide Regulation-Down requirement is in excess of the sum of the SPP system-wide Mid-Term Load Forecast and fixed Export Interchange Transactions, the SCUC algorithm study will, in priority order: (1) curtail non-firm fixed Import Interchange Transactions until the capacity surplus is eliminated; (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limit on an economic basis until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement to the extent possible; (3) de-commit Resources that were committed in the DA Market with a Commit Status of Market until the capacity surplus is eliminated; and (4) de-commit Self-Committed Resources that were committed following the Day-Ahead RUC process until the capacity surplus is eliminated.

(i) If there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, RUC may commit additional Resources to relieve the constraints provided that the additional commitment does not aggravate the excess capacity situation.

c) To the extent that a particular reliability issue cannot be directly addressed within the SCUC algorithm as described under subsection (a) and (b) above, SPP may manually commit Resources including Resources with a Commit Status of Reliability and de-commit Resources, including Resources with a Commit Status of Self, to alleviate such reliability issues in accordance with its authority as Reliability Coordinator.

d) An emergency condition Local Reliability Issue may arise within the operating area of a local Transmission Operator that may involve elements not monitored by SPP. Such emergencies—Local Reliability Issues may require out of merit commitment, decommitment or dispatch instructions to be issued to one or more Resources to resolve the Emergency Local Reliability Issue. Time permitting, the local Transmission Operator shall request SPP to issue such instructions. To the extent time does not permit, the local Transmission Operator may issue such instructions to the Resource in accordance with its authorities as a reliability entity. In such cases, the following shall take place:
(i) If initial instructions are issued by a local Transmission Operator, the Transmission Operator shall notify SPP of the instructions given to the Resource.

(ii) The Transmission Operator and SPP will coordinate to ensure subsequent instructions are provided by SPP.

(iii) SPP shall log such instructions as manual commitment, decommitment or Out-of-Merit Dispatch instruction, as appropriate, as if it gave such instruction to the Resource.

(iv) The Resource shall be eligible to receive the compensation for such instructions whether issued by SPP or the local Transmission Operator in the same manner as if it had been committed by SPP, provided that SPP determines that the Resource was selected in a non-discriminatory manner. For purposes of making such determination, the standards and procedures applicable to Resource selection in the Intra-Day Reliability Unit Commitment process as described in Section 6.1.2.1 of Attachment AE to the Tariff, shall apply. Recovery of such compensation shall be collected locally as described under Section 4.5.9.10.

(e) In the event of a Transmission Operator directive, the Transmission Operator and SPP shall collaborate to provide a report with an after-the-fact analysis of the event. All such reports shall be made available to the appropriate stakeholder groups for review on a quarterly basis in the month following the end of the quarter in which the event occurred and will be used to determine the best practice for addressing this type of emergency situation in the future.

(e) In the event that the local transmission operator commits a Resource to resolve an issue other than a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by SPP, provided that SPP determines that the selected Resource was selected in a non-discriminatory manner. For purposes of making such determination, the standards and procedures described in Section 6.1.2.1 of Attachment AE to the Tariff shall apply. Recovery of such compensation shall be collected regionally as described under Section 4.5.9.10.

(f) In the event that SPP commits a Resource at the request of a local transmission operator to resolve an issue other than a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by SPP. Recovery of such compensation shall be collected regionally as described under Section 4.5.9.10.

(g) In the event that SPP commits a Resource at the request of a local transmission operator to resolve a Local Reliability Issue, the Resource will be compensated in the same manner as if it had been committed by SPP. Recovery of such compensation shall be collected locally as described under Section 4.5.9.10.
Attachment AE

1.1 Definitions H

Head-room

The additional committed capacity required above the average load for the hour due to the uncertainty of the real-time instantaneous load, hourly load forecast and Variable Energy Resource output.

1.1 Definitions F

Floor-room

The reduction in committed capacity required below the average load for the hour due to the uncertainty of the real-time instantaneous load, hourly load forecast and Variable Energy Resource output.

3.1.4 Operating Reserve, Head-room and Floor-room Requirements

The Transmission Provider shall calculate the amount of Operating Reserves required for the Operating Day, on both a system-wide and Reserve Zone basis, in order to comply with the reliability requirements specified in the SPP Criteria. In addition, the Transmission Provider shall calculate the amount of Head-room and Floor-room required for the Operating Day on a system-wide basis in order to ensure that load can be reliably serviced in real-time. The Transmission Provider shall, on a daily basis:

1) Calculate the hourly Regulation-Up, Regulation-Down and Contingency Reserve requirements on an SPP Balancing Authority Area basis and post such results by 0700 hours Day-Ahead for use in the Day-Ahead Market, Day-Ahead RUC, Intra-Day RUC and RTBM;

2) Calculate the total minimum and total maximum Operating Reserve requirement for Operating Reserve deployment in the up direction and for deployment of Operating Reserve in the down direction for each Reserve Zone. These minimum and maximum Operating Reserve requirements will be determined by conducting a simulated energy
transfer study for each hour of the Operating Day on the transmission system, reflecting expected outages and economic energy flows, in order to determine the energy transfer limitations into or out of a Reserve Zone in any hour. If a Reserve Zone is unable to import enough Energy after a contingency and still maintain all necessary operating limits, a minimum amount of Operating Reserve may be required to be carried in that Zone. The minimum Operating Reserve requirement is the largest difference between the Resource MW lost in the simulated contingency and the resulting import capability of that Reserve Zone. Similarly, if a Reserve Zone is unable to export additional Energy after a contingency outside of that Reserve Zone, then a maximum amount of Operating Reserve that is deliverable from that Zone will be specified in order to ensure that deliverable reserves are carried in other Zones. The maximum Operating Reserve limitation is equal to the export capability of that Reserve Zone when replacing Energy lost due to a Resource contingency outside of that Reserve Zone. The Transmission Provider may, at its option, set specific Regulation-Up and/or Spinning Reserve minimum requirements for each Reserve Zone, as needed, to address reliability issues that can only be alleviated through carrying synchronized reserves. In such cases, the Transmission Provider will include these minimum Regulation-Up and/or Spinning Reserve requirements when posting the Operating Reserve requirements by 0700 Day-Ahead;

(3) Estimate each Market Participant’s Operating Reserve obligation in each Reserve Zone and provide such information to Market Participants by 0700 hours Day-Ahead. The Transmission Provider shall calculate such estimates by multiplying the system-wide Operating Reserve requirements calculated in (1) above by the Transmission Provider’s estimate of each Market Participant’s load in each Reserve Zone divided by the Transmission Provider’s estimate of system-wide load; and

(4) The Transmission Provider may increase Operating Reserve requirements for the Day-Ahead RUC, Intra-Day RUC and RTBM above the requirements used in the Day-Ahead Market, including changes to Reserve Zone minimums and maximums, as required to meet increases in reliability requirements caused by changes in system conditions; and

(5) Calculate the hourly Head-room and Floor-room requirements on an SPP Balancing Authority Area basis for use in the Day-Ahead Market, Day-Ahead RUC and Intra-Day RUC in accordance with the calculation procedures specified in the Market Protocols.
5.1.1 Day-Ahead Market Inputs

Inputs to the Day-Ahead Market will include the following:

(1) Day-Ahead Market Resource Offers, Virtual Energy Offers, Demand Bids and Virtual Energy Bids;
(2) Resource Offers for long lead time Resources selected by the Transmission Provider for commitment during the Multi-Day Reliability Assessment process;
(3) Through Interchange Transactions with confirmed Transmission Service reservations;
(4) Export Interchange Transaction Bids with confirmed Transmission Service reservations;
(5) Import Interchange Transaction Offers with confirmed Transmission Service reservations;
(6) Operating Reserve requirements (system-wide and Reserve Zone minimum and maximum);
(7) Transmission System topology consistent with the Network Model in place for the upcoming Operating Day;
(8) Actual and approved scheduled Transmission System outages as documented in the Transmission Provider’s outage scheduler;
(9) Actual and approved scheduled Resource outages as documented in the Transmission Provider’s outage scheduler; and
(10) The Transmission Provider’s estimate of Parallel Flows.
(11) Head-room and Floor-room requirements.

5.1.2 Day-Ahead Market Execution

The Transmission Provider will employ a simultaneous co-optimization methodology to perform the following tasks in order to clear the Day-Ahead Market for each hour of the upcoming Operating Day:

(1) Commit Offered Resources, Import Interchange Transaction Offers and Virtual Energy Offers using the SCUC algorithm to meet the Demand Bids, Virtual Energy Bids, Export Interchange Transactions Bids, Head-room requirements, Floor-room requirements and Operating Reserve requirements on a least cost basis for each hour of the upcoming Operating Day.
   (a) The Day-Ahead Market SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c)
of this Attachment AE, including Resources committed in the Multi-Day Reliability Assessment, up to the Resources’ Maximum Economic Capacity Operating Limit or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up, and down to the Resources’ Minimum Economic Capacity Operating Limit or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down.

(i) If this capacity is not sufficient to meet the fixed Demand Bids and fixed Export Interchange Transaction Bids, Head-room requirements plus Operating Reserve requirements on a system-wide basis, the Day-Ahead Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible.

(ii) If there is a capacity surplus on a system-wide basis calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transaction Offers, Floor-room requirement and the Regulation-Down requirement that is in excess of the sum of fixed Demand Bids and fixed Export Interchange Transaction Bids, the Day-Ahead Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; and (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limits until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement.

(b) To the extent that a particular reliability issue cannot be directly addressed within the Day-Ahead Market SCUC algorithm as described under Subsections (i) and (ii) above, the Transmission Provider may manually commit Resources to alleviate such reliability issues. The Transmission Provider will re-run the Day-Ahead SCUC algorithm after such manual commitments, time permitting, and will notify the Market Participants that units were manually committed.
5.2.1 Day-Ahead Reliability Unit Commitment Inputs

Inputs to the Day-Ahead RUC will include the following:

1. RTBM Resource Offers;
2. Confirmed cleared Export Interchange Transaction Bids from the Day-Ahead Market;
3. Confirmed cleared Import Interchange Transaction Offers from the Day-Ahead Market;
4. Confirmed cleared Through Interchange Transactions from the Day-Ahead Market;
5. Confirmed Export Interchange Transactions specified for use in the RTBM only;
6. Confirmed Import Interchange Transactions specified for use in the RTBM only;
7. Confirmed Through Interchange Transactions specified for use in the RTBM only;
8. Operating Reserve requirements (system-wide and Reserve Zone minimum and maximum);
9. Transmission Provider load forecast;
10. Transmission System topology consistent with Network Model in place for the upcoming Operating Day;
11. Resource commitment schedules from the Day-Ahead Market unless the Transmission Provider is informed by the Market Participant that the Resource is unable to meet its Day-Ahead Market cleared Resource Offers;
12. Commitment schedules for long lead time Resources selected in the Multi-Day Reliability Assessment unless the Transmission Provider is informed by the Market Participant that the Resource is unable to meet its commitment schedule;
13. The Transmission Provider’s wind Resource MWh output forecast;
14. Actual and approved scheduled Transmission System outages as documented in the Transmission Provider’s outage scheduler;
15. Actual and approved scheduled Resource outages as documented in the Transmission Provider’s outage scheduler; and
16. The Transmission Provider’s estimate of Parallel Flows; and
17. Head-room and Floor-room requirements.

5.2.2 Day-Ahead Reliability Unit Commitment Execution

The Transmission Provider will perform a capacity adequacy analysis for the upcoming Operating Day using the SCUC algorithm with the objective of committing Resources to meet
the Transmission Provider load forecast, Export Interchange Transactions, Head-room requirements, Floor-room requirements and Operating Reserve requirements less Import Interchange Transactions over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined in the submitted Energy Offer Curve.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, up to the Resources’ Maximum Economic Capacity Operating Limit or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up, and down to the Resources’ Minimum Economic Capacity Operating Limit or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down.

(a) If this capacity plus Import Interchange Transactions is not sufficient on a system-wide basis to meet the Transmission Provider load forecast, Export Interchange Transactions, Head-room requirements plus and Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement.

(b) If there is a capacity surplus on a system-wide basis calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transactions Offers, Floor-room requirements and the Regulation-Down requirements that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transaction Bids, the SCUC algorithm will, in priority order: (1) curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limits until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement; (3) de-commit
Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and (4) de-commit self-committed Resources until the capacity surplus is eliminated.

### 6.1.1 Intra-Day Reliability Unit Commitment Inputs

Inputs to the RUC will include the following:

1. RTBM Resource Offers;
2. Confirmed Export Interchange Transactions;
3. Confirmed Import Interchange Transactions;
4. Confirmed Through Interchange Transactions;
5. Operating Reserve requirements (system-wide and Reserve Zone minimum and maximum);
6. Transmission Provider load forecast;
7. Transmission System topology consistent with Network Model;
8. Resource commitment and de-commitment schedules from the Day-Ahead RUC or previous Intra-Day RUCs;
9. The Transmission Provider’s wind Resource MWh output forecast;
10. Actual and approved scheduled Transmission System outages as documented in the Transmission Provider’s outage scheduler;
11. Actual and approved scheduled Resource outages as documented in the Transmission Provider’s outage scheduler; and
12. The Transmission Provider’s estimate of Parallel Flows; and
13. **Head-room and Floor-room requirements.**

### 6.1.2 Intra-Day Reliability Unit Commitment Execution

Using the inputs described in Section 6.1.1, the Transmission Provider will perform a capacity adequacy analysis using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider’s load forecast, **Export Interchange Transactions, Head-room requirements, Floor-room requirements** and Operating Reserve requirements **less Import Interchange Transactions** over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers.
(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined on the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the SCUC in making commitment decisions.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, only including capacity up to the Resources’ Maximum Economic Capacity Operating Limits (or Maximum Regulation Capacity Operating Limits if selected for Regulation-Up) and down to the Resources’ Minimum Economic Capacity Operating Limits (or Minimum Regulation Capacity Operating Limits if selected for Regulation-Down).

(a) If this capacity plus Import Interchange Transactions is not sufficient on a system-wide basis to meet the Transmission Provider’s load forecast, Export Interchange Transactions, Head-room requirements and Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement.

(b) If there is a system-wide capacity surplus calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transactions, Floor-room requirements and the Regulation-Down requirements that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transaction Bids, the Day-Ahead Market SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) Incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limits until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement; (3) De-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and (4) De-commit self-committed Resources until the capacity surplus is eliminated.
Proposed Criteria Language Revision

N/A
Southwest Power Pool, Inc.
MARKET OPERATIONS AND POLICY COMMITTEE
Recommendation to the Board of Directors
October 29, 2013
2015 Integrated Transmission Planning 10-Year Assessment Scope

Organizational Roster
The following persons are members of the Transmission Working Group (TWG):

- Noman Williams (Chairman), Sunflower
- Travis Hyde (Vice-Chairman), OG&E
- Mo Awad, Westar Energy
- Scott Benson, LES
- John Boshears, CUS
- John Fulton, SPS
- Joe Fultz, GRDA
- Dan Lenihan, OPPD
- Randy Lindstrom, NPPD
- Jim McAvoy, OMPA
- Matt McGee, AEP
- Nathan McNeil, Midwest Energy
- Nate Morris, Empire District Electric
- Michael Mueller, AECC
- Alan Myers, ITC Great Plains
- John Payne, KEPCo
- Jason Shook, ETEC (GDS Associates)
- Tim Smith, WFEC
- Mike Swearingen, Tri-County Electric
- Harold Wyble, KCP&L

The following persons are members of the Economic Studies Working Group (ESWG):

- Alan Myers (Chairman), ITC Great Plains
- Kip Fox (Vice-Chairman), AEP
- Randy Collier, CUS
- Paul Dietz, Westar Energy
- Leon Howell, OG&E
- Tim Owens, NPPD
- Kurt Stradley, LES
- Mike Swearingen, Tri-County Electric
- Greg Sweet, Empire District Electric
- Al Tamimi, Sunflower
- Bruce Walkup, AECC
- Michael Watt, OMPA
- Bennie Weeks, Xcel Energy
- Mike Proctor, Liaison Member
- James Sanderson, Liaison Member

Background
The 2015 Integrated Transmission Planning 10-Year Assessment (ITP10) will be a value-based assessment analyzing the 10-year out transmission system (i.e. 2024) and identifying 100 kV and above solutions to needs stemming from multiple sources: (a) needs identified in the reliability analysis of the 69 kV and above system, (b) needs identified to meet projected renewable policy mandates and goals, (c) needs arising from transmission system congestion, and (d) needs arising from instability of the transmission system.

The 2015 ITP10 will be utilized in integrating the 2013 ITP20 with the 100 kV and above facilities to incorporate such needs as the following: a) resolving criteria violations; b) mitigating known or foreseen congestion; c) meeting projected policy mandates and goals; d) improving access to markets; d) the staging of transmission expansion. This assessment is not intended to review each consecutive year in the planning horizon, but only the horizon year.

Staff has completed work on resource plans for three futures: Business as Usual (Future 1), Decreased Base Load Capacity (Future 2), and Increased Input Prices (Future 3). The MOPC reviewed the results of these plans and moved to remove analysis of the Increased Input Prices future.
Since May, ESWG and TWG have been working with Staff to develop the 2015 ITP10 scope. In the July 2013, ESWG and TWG brought several items from the 2015 ITP10 scope, including the futures, to the MOPC and the Board. Based on those decisions and with additional development and review, the working groups and the MOPC have discussed and approved all other details for the 2015 ITP10 scope.

Analysis
To conform to the requirements of SPP OATT Attachment O, the components of the scope include the following sections: working group/committee oversight, stakeholder reviews, the general study process, study assumptions, details of all assessments, a study timeline, and study deliverables. The ESWG and TWG will oversee the components of 2015 ITP10. See the 2015 ITP10 scope document for more details.

Several other major points of the 2015 ITP10 scope not previously reviewed by the BOD include the following: consolidation, staging, sensitivities, metrics, and stability analyses. A final decision to determine which projects are included in the recommended transmission plan will be made after the accomplishment of the MOPC Action Item #223 by April 2014. Staff will stage projects in the final transmission plans starting in year 2019 and staging through 2024. For each project, staging will be based on the future(s) in which it was required.

To measure the value of the final plans, staff will calculate benefits on the following metrics: APC Savings; Value of Replacing Previously Approved Projects; Reduced Losses; Reduced Capacity Costs; Reduction of Emissions Rates and Values; Public Policy Benefits; Assumed Benefit of Mandated Reliability Projects; and Mitigation of Transmission Outage Costs. The calculation and allocation methods for these benefit metrics will be reviewed by the ESWG and the TWG and finalized in April 2014. For sensitivities on the final transmission plans, staff will conduct sensitivities on natural gas price, demand levels, and the Tres Amigas and Clean Line Plains & Eastern DC facilities.

Staff will also conduct stability analyses on the final transmission plans. TWG requested the analysis include dynamic stability and voltage stability assessments.

The 2015 ITP10 will be an 18-month study, started in July 2013 and scheduled to be finalized in January 2015. The study scope was approved by the TWG on September 18, 2013, by the ESWG on October 2, 2013 and by the MOPC on October 16, 2013.

Recommendation
The MOPC recommends that the BOD approve the 2015 ITP10 Scope.

Approved:

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Action Requested: Approved Recommendation
2015 ITP10 Scope

Approved by ESWG: 10/02/2013
Approved by TWG: 09/18/2013

ESWG / TWG / SPP Staff
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Overview

This document presents the scope and schedule of work for the Integrated Transmission Planning (ITP) 10-Year Assessment. This document will be reviewed by the Transmission Working Group (TWG) and the Economic Studies Working Group (ESWG) beginning May 2013, with the expectation of approvals from the Market Operations and Policy Committee (MOPC) and the Board of Directors (BOD) in October 2013. The assessment begins in July 2013 and is an 18-month study scheduled to be finalized in January 2015.
Objective

The 2015 ITP 10-Year Assessment (ITP10) is a value-based planning approach that will analyze the 10-year out Transmission System and identify 100kV and above solutions to needs stemming from multiple sources: (a) needs identified in the reliability analysis of the 69 kV and above system, (b) needs identified to meet projected renewable policy mandates and goals, (c) needs arising from transmission system congestion, and (d) needs arising from instability of the transmission system.

The 2015 ITP10 will be utilized in integrating the 2013 ITP20 with the 100kV and above facilities to incorporate such needs as the following: a) resolving criteria violations; b) mitigating known or foreseen congestion; c) meeting projected policy mandates and goals; d) improving access to markets; d) the staging of transmission expansion. This assessment is not intended to review each consecutive year in the planning horizon, but only the horizon year.
**Stakeholder Process**

**Working Group Involvement**

The 2015 ITP10 will be vetted through the SPP working groups. The ESWG will oversee the economic portions of the 2015 ITP10 and all related data and assumptions. The TWG will oversee the reliability portions of the 2015 ITP10 and all related data and assumptions. The following items will be discussed at the respective working groups:

Regional Cost Allocation Review Task Force (RARTF)

A regional cost allocation review study will be performed in conjunction with the ITP10 process to identify potential project solutions to mitigate Benefit inequities which exist in certain zones.

Transmission Working Group (TWG), Model Development Working Group (MDWG)

The TWG and/or the MDWG will be responsible for reviewing the data and results for the following items:

1) Scope
2) Futures - Approval
3) Load Forecast – Peak Demand
4) Steady State Models
5) Constraint Review
6) Reliability Assessment
7) Stability Assessment
8) Transmission Plan Development
9) Benefit Metrics
10) Report

Economic Studies Working Group (ESWG)

The ESWG will be responsible for reviewing the data and results for the following items:

1) Scope
2) Futures – Development and Approval
3) Policy Survey
4) Load Forecast - Energy
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5) Generator Review

6) Resource Plan and Siting

7) Economic Modeling Assumptions

8) Policy Assessment

9) Economic Assessment

10) Transmission Plan Development

11) Benefit Metrics

12) Sensitivities

13) Report

Markets and Operations Policy Committee (MOPC)
The MOPC will be sought for endorsement of the following items:

1) Scope

2) Futures

3) Policy-Driven Decisions

4) Metrics

5) Report

Strategic Planning Committee (SPC)
The SPC will be sought for endorsement of the following items:

1) Futures

Seams Steering Committee (SSC)
The SSC will be responsible for the review of the following item:

1) Seams Impacts

Regional State Committee (RSC)
The RSC will be responsible for the following items:

1) Approve Cost Allocation

2) Review the final Report and endorse as appropriate

Board of Directors (BOD)
The BOD will approve the following items:
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1) Transmission Plan

2) Cost and Benefit Allocation

3) Report

The final 2015 ITP10 Report will be approved by the BOD.

**Stakeholder Reviews**

The following is a list of reviews to be provided by stakeholders during the 2015 ITP10 study:

**Load Forecast Review**

Projected peak load per area for the year 2019 and 2024 will be submitted by the modeling contacts for the development of a peak 2019 and 2024 model. Energy per area for 2019 and 2024 will be obtained from publicly available sources and reviewed and updated by stakeholders. Stakeholders will review projected peak load and energy per area. Peak load and energy will also be identified for load serving entities within SPP RTO areas (for example, Hastings Utilities and City of Grand Island load will be reviewed by NPPD).

**Policy Survey**

Stakeholders will provide feedback through a survey, conducted by the ESWG, on current and planned renewable generation plants.

**Generation Resource Plan Review**

ESWG will review the data for all generators added to the model as part of the 2015 ITP10 resource plan. This will include conventional and renewable generation. The review will focus on the siting and capacity of new units. For conventional generation, the zonal demand and capacity figures will be provided, as well as expected capacity margins for 2024. For renewable generation, the siting, capacity, and average capacity factor of each new resource will be provided. This will include resources identified as a part of the Policy Survey and may include renewable resources identified by the resource planning software.

**Economic Model Review**

ESWG will be provided with model data indicating generators and the parameters used in the economic model. Non-confidential parameters such as maximum capacity, ramp rates, O&M costs, etc. will be provided for review. For confidential parameters, such as heat rates, publicly available data will be utilized. However, resource owners may modify the publicly available data to more accurately model their generator’s characteristics as appropriate.

**Constraint Assessment Review**

A list of constraints will be developed to be used in the economic dispatch, as detailed in the Constraint Review Section below. The constraints will be provided to the TWG for review; they will approve the final list of constraints to use, as well as the associated constraint ratings.
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**Power Flow Model Review**
TWG and MDWG will review the economically-dispatched power flow models and provide feedback. The review will focus on the reactive needs.

**Project Development Request**
Stakeholders will be asked to provide suggestions on projects they believe should be analyzed in the study. All stakeholder-submitted project requests will be analyzed to assess the project’s potential to meet needs. This includes reliability, economic, and policy needs as detailed in the Analysis Section of this document.
Study Process

1. The futures will be selected and assumptions refined through the various stakeholder groups (ESWG, TWG, MOPC, RSC).

2. The ESWG will oversee the development of the economic models that incorporate the assumptions developed in step #1 above, including review of data and results. Similarly, the TWG will oversee the development of the power flow and stability models used in this analysis, including a summer peak case and an off-peak case. These will be developed through the existing SPP Planning Model Process via the MDWG.

3. Constraints will be developed through the identification of congested facilities and by performing transfer analyses. All constraints will be 100 kV and above facilities for 100 kV and above facility outages within SPP and first-tier neighborsystems.

4. Staff will perform an initial AC analysis using applicable NERC Reliability Standards and SPP Criteria on power flow models that represent the applicable load profiles and generation dispatch associated with each future. The assessments will be limited to the planning horizon year. All facilities 69 kV and above in the models will be monitored within SPP and the first-tier for this analysis as a means to determine 100 kV and above solutions for SPP to the problems identified. The TWG will review the results.

5. Concurrently, an economic assessment will be performed to analyze congested facilities on the SPP Transmission System. This will be done using a security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) model over 8,784 consecutive hours.

6. 100 kV and above solutions to criteria violations, policy requirements, and/or congested facilities will be identified with input from stakeholders and coordinated as applicable with SPP neighbors. Staff will request suggestions for solutions from stakeholders and perform a preliminary assessment of benefits for these projects. During this phase, Staff will coordinate solutions with the AG and GI Study processes to best accommodate the high-demand areas for the SPP transmission system footprint. Issues identified that are not resolved with 100 kV and above solutions will be deferred to ITP Near-Term Assessments for resolution.

7. A check will be performed to determine if projects identified in the 2013 ITP20 will eliminate or defer any projects identified in the 2015 ITP10. This check will be performed by replacing lower voltage solutions with the higher voltage solutions identified in the 2013 ITP20 and re-running the economic and contingency analysis. The economic analysis will include calculating benefit and cost for each alternative.
Southwest Power Pool, Inc.

8. A follow-up analysis will be performed by Staff repeating the steps above on the identified solutions to validate the solutions and check for any additional criteria violations and/or congested facilities that may have been created.

9. A sensitivity analysis will be performed on the recommended portfolio to assess how versatile the plan is in handling a range of uncertainties.

10. Benefit metrics will be calculated for the recommended portfolio for each future.

11. A 40-year financial analysis will be conducted on the recommended portfolio.

12. Stability analyses will be conducted on the recommended portfolio to determine if voltage stability requirements for the region are met. Dynamic stability analysis will be performed on the Business As Usual Future. A wind transfer voltage stability analysis will be performed on each future.
Data inputs

Economic

The analysis for the 2015 ITP10 will utilize engineering models to facilitate the development of long range transmission plans. One set of models will be the economic models used to produce a market based resource dispatch used in the analysis. These models require certain assumptions regarding generation resources, parameters, and locations (detailed in the following sections). The output of these models will allow engineers to identify the appropriate transmission additions needed from an economic perspective. This output can also be used to determine deliverability of the resources needed to market used in the analysis.

The major assumptions needed to construct the economic models are detailed below and contain, but are not limited to: market structure, load forecasts, resource forecasts and parameters, transmission topology, renewable assumptions, fuel pricing and availability, etc. Once these assumptions are input into the model, it will perform a security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED).

The following sections detail the parameters to be used in the economic portion of modeling.

Market Structure

SPP anticipates implementing its Integrated Marketplace and Consolidated Balancing Authority (CBA) in March 2014. The Integrated Marketplace and CBA will be baseline assumptions for the analysis.

Futures

Future 1: Business as Usual

This future will include all statutory/regulatory renewable mandates and goals as well as other energy or capacity as identified in the policy survey, load growth projected by load serving entities through the MDWG model development process, and the impacts of existing regulations. This future assumes no major changes to policies that are currently in place.

Future 2: Decreased Base Load Capacity

This future will consider factors that could drive a reduction in existing generation. It will include all assumptions from the Business as Usual future with a decrease in existing base load generation capacity. This future will retire coal units less than 200 MW, reduce hydro capacity 20% across the board, and utilize the Palmer Drought Severity Index for an average of August 1934 and August 2012 to simulate a reduction in existing capacity affected by drought conditions: 10% under moderate, 15% under severe, and 20% under extreme. These target reductions may be adjusted based on locational and operational characteristics within each zone.

Load Forecasts

The study will require load forecasts for SPP members and non-members within the SPP footprint, as well as areas outside of the SPP footprint, for the year 2019 and 2024. SPP Staff queries its
members through the MDWG for applicable load forecasts to use in each of the zones for the modeling footprint. The base model will also include additional load expected in the SPP region. This load will include a 50/50 forecast from the High Priority Incremental Load Study (HPILS) and will be vetted through the ESWG and the TWG. Energy forecasts will be provided by the ESWG and other contacts. Load shapes will be obtained from publicly available data for the typical load projections and requested from stakeholders for the HIPILS loads. Load shapes will be benchmarked as detailed in the Benchmarking Section.

For load forecasts outside of the SPP footprint, SPP will request load forecasts from SPP tier 1 neighbors. If data is not provided, publicly available data will be utilized as the source of the load forecasts, where available. If unavailable, publicly available information on projected load growth will be extrapolated to develop a representation for load expected in the study timeframe.

**Resource Plan**

A generation resource plan for 2019 and 2024 will be developed for use in the study for each future. This resource plan will include both renewable and conventional generation. Additionally, new renewable and conventional generation resources will be sited as detailed below.

Each SPP RTO load serving member must meet the current 12% capacity margin requirement outlined in SPP Criteria 2.1.9. The siting of new generation in the resource plan will target a 12% capacity margin for each zone. Capacity needs will be identified for each future for 2019 and 2024.

Renewable generation, for the purposes of this study, includes hydro, wind, solar, and bio-fuel. Designated renewable resources will be identified through the policy survey. Additional renewables will be included in the plans, as needed, to meet the renewable projections, as supplied by the Policy Survey. Additional renewables identified by the resource planning software may also be included. The renewable ownership designations will be reviewed by stakeholders and posted on SPP.org. SPP tier 1 neighbors will be provided the opportunity to provide feedback and input into the generation resource plan for their area.

**System Topology**

The focus of the Study is to develop a comprehensive, flexible, and cost-effective transmission expansion plan to meet the requirements of the SPP footprint under various futures.

Power flow models will be required for the Study for both the economic and reliability assessments. The starting point of these power flow models will be the latest MDWG information from Model on Demand™, which includes the current projects from the latest SPP Transmission Expansion Plan (STEP). These power flow models will serve as an input into the economic (production) modeling program to develop a market based economic dispatch for the system.

Two new DC interconnections, the Tres Amigas DC Tie and the Clean Line Plains & Eastern project, will be included in the models for sensitivity analysis only.

**Economic Model Generation Parameters**

The generation parameters (Startup cost, operating costs, Min/Max Operating Levels, etc.) will be updated by the ESWG as part of the economic model review.
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Renewables
Renewable generation, primarily wind, hydro, and solar, operate as energy resources that will require the development of hourly generation profiles for individual plants based on historical data or modeled time-series wind speed datasets. These generation profiles will be time-synchronized with coincident historical load shapes. The economic dispatch model will attempt to realistically model renewable generation curtailment, based on expected market conditions and reliability requirements. A curtailment price consistent with the variable O&M cost will be used to simulate the behavior of the wind generation within the Security Constrained Economic Dispatch (SCED). The ESWG will review the behavior and costs of the renewable generation against appropriate benchmarks.

Siting
The expected location of future generation will be considered in areas with appropriate potential. These sites will be further developed and refined as a subset of those selected in the 2013 ITP20 study, as appropriate for the futures of this study. SPP will request that tier 1 neighbors provide siting based on SPP’s identification of capacity needs from the resource plan. If siting is not provided, SPP will site new generation.

DC Ties and Lines
DC ties and lines connect SPP to the WECC and ERCOT and Eastern Interconnect systems. Confirmed long-term firm transmission service will be used as a basis for modeling the flow levels of DC ties and lines. Hourly profiles will be developed based on 3-year historical flows on the DC facilities, limited to boundaries of existing long-term firm service commitments. The hourly profiles will be vetted with ESWG and TWG. The cost of energy purchases and sales across the DC ties will be calculated using the hourly average zonal generation locational marginal price of each utility owner multiplied by their ownership share of the output. No curtailment price will be assumed for the long-term firm service profile. For those DC ties or lines with no confirmed long-term firm transmission service, Staff will model no flow across the DC ties and lines.

Fuel Prices
Fuel forecasts will be utilized in the resource planning, production cost modeling, and benefit metric calculations. Fuel prices for coal, oil, and uranium, including transportation costs, will be forecasted for the 2024 study year based upon the latest VentyxReferenceCase available at the onset of the study. NYMEX futures will be utilized for natural gas prices, out to the latest year for which the futures are available. For natural gas prices beyond this year, growth rates from the DOE Annual Energy Outlook will be utilized. The specific NYMEX and DOE numbers will be developed during the resource planning phase of the study and then locked down for the remainder of the study.

Environmental Policy
Emission price forecasts for SO₂, NOₓ, and CO₂ for the 2024 study year will be based upon the latest VentyxReferenceCase data available at the onset of the study.
Policy Survey

A policy survey will be administered by the ESWG and will be used by stakeholders to provide assumptions regarding specific renewables information. The previous renewables surveys will be used as a reference for development of the current survey. The survey will contain, at a minimum, the following information:

- Name, zone, and capacity for all specific renewable sites that are in-service or expected to be in-service by the end of 2014;
- Renewable energy totals for 2024 and 2019 based on state and utility mandates, goals, and other utility company policy;

For all renewable sites in the models, the renewable energy output for each hour of the year will be based on the maximum capacity provided in the survey. Capacity factors and hourly profiles will be based on expected or historical behavior. Calculations for policy requirements will incorporate stakeholder specific inputs, and capacity factors for wind used in the Study will be based on NREL wind profiles that correspond to a similar location as the wind site and are based on historical weather patterns. For new wind sites to meet the requirements of the Policy Survey and resource plan, a 15% increase will be applied to the existing capacity factors being utilized for each of the NREL sites.

Hurdle Rates

Hurdle rates will be utilized in the economic model between SPP and neighboring systems to help keep imports and exports at a reasonable exchange levels. Hurdle rates for imports and exports between SPP and other entities will be determined during the benchmarking process.

Hurdle rates between non-SPP entities will be set as needed to model minimal and reasonable exchange between these entities.

Benchmarking

After all assumptions and data are included in the economic model, it will be benchmarked against historical system behavior. This benchmarking will be used to assess the reasonability of the simulations.

In order to complete the 2015 ITP10 benchmarking effort, a model will be developed based upon the year 2013. Simulation results from that economic model will be compared with historical statistics and measurements from the SPP real time data, NERC data, and the Energy Information Administration data.

The ESWG will review the benchmarking data as part of the model review process. Specific benchmarks will include some or all of the following: capacity factor by unit type, generation by unit category, maintenance outages, load shapes, renewable generation profiles, operating, and spinning reserve levels, coal transportation costs, system Locational Marginal Prices (LMPs), flowgate loading, production costs, generation dispatch order, and zonal purchases and sales.
**Steady State**

Being that SPP will implement its Integrated Marketplace and CBA in 2014, powerflow models with a market dispatch under coincident peak load and off-peak load will be developed.

Steady state analysis will be conducted using output from the economic models as a starting reference for load and generation dispatch. These models will be utilized in additional engineering tools in order to conduct an assessment to determine the SPP system’s voltage and thermal impacts. This steady state assessment is detailed in sections below.

**Load**

The load density and distribution for the steady state analysis will be reviewed by the MDWG. Resource obligations will be determined for the footprint taking into consideration what load is industrial, non-scalable type loads and which load grows over time. The MDWG, TWG, and ESWG provide collaborative feedback into the determination of this impact. The load used in the steady state analysis will be the same as that used in the economic model as described in Section: Load Forecast.

**Generation Resources**

The generating resources determined through Section A.III: Resource Plan will be added to the power flow. Each future will contain a different subset of generation resources and correspond to a unique power flow case. These generating resources will be reviewed by the ESWG and will correspond to the economic analysis conducted for the Study.

**Steady-State System Topology**

The topology used in the steady state analysis will be the same as that used in the economic model as described in Section: System Topology.

**Exports/Imports to First Tier**

The exports/imports used in the steady state analysis between SPP and neighboring AC systems will be determined by the economic dispatch model. Exports and imports between DC interconnections will be based on historical hourly scheduling of long-term firm transmission service. This economic exchange of energy between neighboring systems will be modeled for the steady state analysis.

**Market Dispatch**

The economic models will be used to determine hourly load profiles and generation dispatch for the steady state analysis. The generation dispatch and corresponding hourly profiles will be mapped from the economic model to the reliability power flow model.
Analysis

Define Constraints
To identify which constraints are applicable in 2024, Staff will begin by reviewing the existing NERC Book of Flowgates (BoF) to determine additions or deletions from the list of constraints (event file) for the economic model. Staff will perform additional analysis using Power Analytics and Trading Tool (PAT) to identify the top constraints by congestion costs (average shadow price times the number of constrained hours) on the system for 8,784 hours. These additional constraints will be reviewed and approved by TWG. The following items will be considered in the analysis:

- The initial constraint list will be the then-current BoF
- Constraints studies will be run over 8,784 hours (1 year)
- This analysis will use the 2024 economic model(s) for each future
- Contingencies 100 kV and above in SPP and first-tier
- Monitored elements 100 kV and above in SPP and first-tier
- Unless other information is available, each constraint’s rating will be selected based upon the applicable Rating A (normal rating) or Rating B (emergency rating) in the power flow model.

Needs Assessments
The reliability, policy, and economic needs of the system will be identified in each future in order to develop a transmission portfolio for each future. Each analysis will be performed in parallel to determine all needs across the system in 2024. All needs identified in the assessments below will be evaluated by Staff for potential consideration in the interregional planning process pursuant to the requirements of Order 1000.

Economic Assessment
The economic needs of the system will be identified in each future in order to develop a portfolio for each future. All of the system needs will be identified through the use of a SCUC & SCED simulation that accounts for 8,784 hours representing each hour of the year 2024.

The SCED will determine nodal Locational Marginal Prices (LMPs) while dispatching the generation economically. The LMPs, among other cost components, reflect the congestion occurring on the power grid’s binding constraints. System congestion will be identified in each of the 8,784 hours. A list of binding constraints will be developed for each future and ranked based upon the average shadow price associated with each constraint. The top twenty constraints based upon this ranking will be identified as economic needs, subject to ESWG review.

Policy Assessment
The policy needs of the system will also be identified for each future in order to develop a portfolio for each future. All of the system needs will be identified through the use of a SCUC & SCED
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simulation that accounts for 8,784 hours representing each hour of the year 2024. Renewable generation may experience the effects of congestion and be curtailed by the SCED. Shortfall in the achievement of the renewable requirements of each future due to this curtailment will be identified. Renewable resources that experience an annual energy output of less than the statutory/regulatory mandate or goal will be identified as policy needs. The required energy is based on maximum capacity, capacity factor, and generation profile.

**Steady State Assessment**

The steady state assessment will use 2024 summer peak and high wind with low load (off peak) models based on a market dispatch. Each future will be evaluated for the same peak and off peak hours. An N-1 contingency analysis will be conducted on each future for the peak and off peak cases. All SPP and first tier facilities 69 kV and above will be monitored for this analysis in development of 100 kV and above solutions.

The non-converged contingencies will be reviewed.

**Stability Assessment**

Dynamic stability analysis will be conducted on the final recommended portfolio for the Business as Usual future to assess transient voltage recovery. It will be conducted on the offpeak model simulating the 2013 TPL Category B and C contingencies identified by members and additional contingencies identified by Staff through the Fast Fault Screening tool. TWG will review and approve Staff identified contingencies for further analysis.

A voltage stability assessment will be conducted on each future using the recommended final portfolio to assess the transfer limit (MW) due to transfer of wind west to east across the SPP footprint. These must be determined by examining voltage performance during power transfer into a load area or across an interface. The stability assessment consists of a wind dispatch analysis to determine if the dispatched wind generation in the 2015 ITP10 2024 summer peak models in all futures can be dispatched without the occurrence of voltage collapse or thermal violations.

**Solution Development**

Staff will solicit stakeholders for possible solutions to the needs. A pool of possible solutions will be used to mitigate the economic, reliability, and policy needs in creating the 2015 ITP10 transmission plan. This pool of solutions will come from transmission service studies, generation interconnection studies, previous ITP studies, and stakeholder input. Solutions developed could meet more than one need (i.e. economic, policy, and/or reliability needs) and will be classified as project types based on the criteria outlined below. To the extent benefit to cost deficient zones are identified as a result of the Regional Cost Allocation Review, remedies will be evaluated and recommended by Staff, in coordination with the deficient zones and appropriate stakeholder groups, as part of the 2015 ITP10 analysis as appropriate.

Based on the criteria below, Staff will develop a plan for each future. Staff will then consolidate the projects from each future into a recommended plan.
Economic Project Solutions

Economic projects will be developed and evaluated based upon how well they mitigate congestion. Any economic project with a one-year B/C ratio of 0.9 or greater will be included for further evaluation.

Economic seams projects will be initially evaluated and considered under the assumption that the project would be cost shared with an SPP neighbor, with SPP paying for 80% of the cost and the neighbor paying 20% of the cost. As the evaluation progresses and the SPP neighbor identifies the level with which the transmission project benefits them, then the cost percentages should be updated to a more accurate reflection of the benefit distribution.

Policy Project Solutions

Policy projects will be developed and evaluated based upon how well they mitigate curtailment of renewable energy required by the regulatory/statutory mandates and goals as defined by the 2015 ITP10 policy survey. Any policy project that helps to mitigate curtailment of renewable requirements will be included for further evaluation.

Reliability Project Solutions

Reliability projects will be developed and evaluated based upon how well they mitigate member criteria violations for the peak and offpeak hours.

Interregional Considerations

Seams projects will be considered as part of the 2015 ITP10 study and expansion plan as potential solutions, and SPP will collaborate with neighboring entities regarding the identified needs, benefits, potential solutions, and costs. For the neighbors that SPP has an agreement with, joint coordination will be done in accordance with that agreement.

Final Recommended Portfolio

[This section was left blank intentionally. A decision regarding the final portfolio recommendation will be made after the accomplishment of the MOPC Action Item #223 by April 2014].

Forty-Year Financial Analysis

The 2015 ITP10 shall assess the cost effectiveness of the recommended portfolio over a forty-year time horizon in accordance with Section III.3.c of Attachment O of the SPP OATT. To estimate the benefits over 40 years, Adjusted Production Cost (APC) savings will be calculated for the two model years developed, 2019 and 2024. The slope between the selected points will be used to extrapolate the benefits beyond 2024 over a 40 year timeframe. The costs will be calculated using the formula for Annual Transmission Revenue Requirement (ATRR). The total benefits and costs will be reported in net present value (NPV) dollars.

Benefit and impact calculations will be made on a Regional, Zonal, and State basis. State values will be extrapolated from the zonal costs and benefits. Many zones are only in one state. For those zones
that are only in one state, their full portion of both costs and benefits will be allocated to the state. For zones crossing state borders, their portion of both costs and benefits will be allocated to each state based on their percentage of load that is in each state.

Net benefits and B/C ratios will be calculated based on NPV benefit and NPV cost and will be reported based on present dollars (2014).

**Benefit Metric Development and Usage**

The metrics used to measure the value of the final portfolio in the 2015 ITP10 are identified here and will be vetted with the ESWG. These metrics will be used to measure the value of the final consolidated portfolio on each future.

<table>
<thead>
<tr>
<th>Metric Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>APC Savings</td>
</tr>
<tr>
<td>Value of Replacing Previously Approved Projects</td>
</tr>
<tr>
<td>Reduced Losses</td>
</tr>
<tr>
<td>Reduced Capacity Costs</td>
</tr>
<tr>
<td>Reduction of Emissions Rates and Values</td>
</tr>
<tr>
<td>Public Policy Benefits</td>
</tr>
<tr>
<td>Assumed Benefit of Mandated Reliability Projects</td>
</tr>
<tr>
<td>Mitigation of Transmission Outage Costs</td>
</tr>
</tbody>
</table>

*Table 1: Monetized Cost Benefit Metrics for 2015 ITP10*

To the extent that any adjustments or changes to Benefit Metrics are recommended by the Regional Allocation Review Task Force (RARTF), these changes will be considered by the ESWG.

**Sensitivities**

Sensitivities will be conducted on the final recommended portfolio for the Business as Usual future to assess how versatile the plan is in handling a range of uncertainties. Economic analysis will be performed for the sensitivities. The following sensitivities will be performed:

- Natural Gas Price
- Demand levels
- TresAmigas and Clean Line Plains & Eastern

Specifics of the DC project sensitivities will be developed and approved by the ESWG.

The sensitivities will be used to measure the viability of the proposed transmission plan that is produced through the 2015 ITP10. These sensitivities will not be used to develop the transmission projects or filter out projects.
Staging
A project implementation plan will be developed for the final recommended portfolio. The final portfolio will be structured such that each element can be implemented in a staged manner as actual system developments approach the assumptions resulting in the need for that element. To help stage the projects SPP will utilize years 2019 and 2024. This section is broken into two parts: one for projects classified to meet one set of needs (i.e. economic, policy, or reliability needs); one for projects meeting multiple needs.

**Single Project Classification**
For economic projects in Future 1, Staff will stage projects based on linear interpolation of B/C ratios from 2019 to 2024 with consideration of lead times. For economic projects in Future 2 and Future 3, Staff will stage them with a 2024 need date.

For policy projects, Staff will stage projects in order to meet the renewable requirements.

For reliability projects in Future 1, Staff will stage projects based on linear interpolation of thermal loadings from 2019 to 2024. All other reliability projects in Future 1 will be staged with a 2024 need date. For reliability projects in Future 2 and Future 3, Staff will stage them with a 2024 need date.

**Multiple Project Classification**
If a project is classified as more than solely economic, policy, or reliability project, the project will be staged to meet the earliest need date established through the Single Project Classification Section with a requirement that for economic projects, the one-year B/C ratio threshold crosses 1.0.

**Reactive Needs**
If any 300 kV and above upgrades are identified as solutions in the portfolio, line-end reactive requirements analysis will be performed for the new transmission lines greater than 300 kV system to provide an indicative amount of reactor needs before design level studies are completed.

**Final Reliability Assessment**
A steady state N-1 contingency analysis will be conducted to identify any remaining outstanding issues on the final recommended portfolio.

**Cost Estimates**
The cost estimates used for projects that are tested in the initial project development phase will be Conceptual Estimates as defined by the SPP Business Practice 7060. The Conceptual Estimates will be developed by Staff and utilize standardized estimates and multipliers that are based on historical data. Projects that pass the initial screening phase will be designated for Study Estimates as defined by Business Practice 7060.
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A Study Estimate will be prepared by the designated TO(s) for non-competitive upgrades and by Staff for competitive upgrades by completing a Standardized Cost Estimate Reporting Template (SCERT) for all upgrades that are required to complete that project. The Study Estimate will provide a more refined cost estimate for potential project approval. For all Study Estimates, Staff will provide TO’s a minimum of six weeks from the date of request before the estimate is due.
## Timeline

The 2015 ITP10 will generally follow the process flow below beginning in July 2013 with final results in January 2015. The estimated timeline is as follows:

<table>
<thead>
<tr>
<th>2015ITP10</th>
<th>Group(s) to review/endorse</th>
<th>Start Date</th>
<th>Completion Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Futures &amp; Scope</td>
<td>ESWG, TWG</td>
<td>April 2013</td>
<td>October 2013</td>
</tr>
<tr>
<td>Policy Survey</td>
<td>ESWG</td>
<td>May 2013</td>
<td>August 2013</td>
</tr>
<tr>
<td>Load Forecast &amp; Generation Review</td>
<td>ESWG, TWG</td>
<td>May 2013</td>
<td>August 2013</td>
</tr>
<tr>
<td>Siting Plan</td>
<td>ESWG</td>
<td>September 2013</td>
<td>October 2013</td>
</tr>
<tr>
<td>Economic Model Development &amp; Review</td>
<td>ESWG</td>
<td>May 2013</td>
<td>December 2013</td>
</tr>
<tr>
<td>Model Benchmarking</td>
<td>ESWG</td>
<td>January 2014</td>
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<tr>
<td>Constraint Review</td>
<td>TWG</td>
<td>November 2013</td>
<td>January 2014</td>
</tr>
<tr>
<td>Economics-distributed Powerflow</td>
<td>TWG</td>
<td>January 2014</td>
<td>April 2014</td>
</tr>
<tr>
<td>Reliability, Policy, Economic Needs Assessment</td>
<td>ESWG, TWG</td>
<td>February 2014</td>
<td>April 2014</td>
</tr>
<tr>
<td>Finalize benefits metrics and allocation methods for ITP10 portfolio analysis</td>
<td>ESWG, TWG</td>
<td>April 2014</td>
<td>April 2014</td>
</tr>
<tr>
<td>Project Development Request</td>
<td>ESWG, TWG</td>
<td>April 2014</td>
<td>May 2014</td>
</tr>
<tr>
<td>Project Grouping</td>
<td>ESWG, TWG</td>
<td>June 2014</td>
<td>June 2014</td>
</tr>
<tr>
<td>Final Recommended Portfolio</td>
<td>ESWG, TWG</td>
<td>June 2014</td>
<td>July 2014</td>
</tr>
<tr>
<td>Project Staging</td>
<td>ESWG, TWG</td>
<td>July 2014</td>
<td>August 2014</td>
</tr>
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<td>Sensitivities Conducted</td>
<td>ESWG</td>
<td>July 2014</td>
<td>September 2014</td>
</tr>
<tr>
<td>Final Benefit Metrics Calculations</td>
<td>ESWG</td>
<td>July 2014</td>
<td>September 2014</td>
</tr>
<tr>
<td>Stability Analyses</td>
<td>TWG</td>
<td>May 2014</td>
<td>September 2014</td>
</tr>
<tr>
<td>Review draft report with recommended solutions</td>
<td>ESWG, TWG</td>
<td>July 2014</td>
<td>September 2014</td>
</tr>
<tr>
<td></td>
<td>MOPC</td>
<td>October 2014</td>
<td></td>
</tr>
<tr>
<td>Final report with recommended solutions</td>
<td>ESWG, TWG</td>
<td>November 2014</td>
<td>December 2014</td>
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<tr>
<td></td>
<td>RSC</td>
<td>January 2015</td>
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<td>MOPC</td>
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</tr>
</tbody>
</table>
10-Year Assessment Process (Initiated Every 3 Years)

Coordinate with Stakeholders to Implement Previous ITP

Scenarios Narrowed
Fewer Scenarios
More Models

Stakeholder Approval of Study Scope Document
ESWG/TWG

Model Development
Will go through ESWG/TWG

Define Additional Flowgates
Monitor All Facilities, Outage 100kV+

Security Constrained Unit Commitment and Economic Dispatch (SCUC & ED) Analysis

Develop Solutions to Congestion and/or Criteria Violations, Coordinate with AG/GI, and Compare Alternatives 100kV+

Receive 20 Year Assessment Solutions

Determine if 20-Year Projects Solve Problems

Validate Solutions and Check for Additional Issues by Repeating Analysis
Perform Stability Analysis

Cost Benefit for Identified Projects/Interactions 345kV+

Stakeholder Review & BOD Approvals

July

December

January

June

January
Deliverables

Final Report and Recommended Portfolio
The results from the 2015 ITP10 will be compiled into a report detailing the findings and recommendations of SPP Staff. The report will include a project list identifying each upgrade. This report will also be incorporated into the 2015 STEP Report.

Staging and Timing of Project Implementation
A project implementation plan will be developed for the recommended transmission plan. The final plan will be structured such that each element can be implemented in a staged manner as actual system developments approach the assumptions resulting in the need for that element. Each element will have at least one of the following justifications: policy, economic or reliability justification. NTCs/NTC-Cswill be issued for the 2015 ITP10 plan elements in accordance with the Tariff, Attachment O, Section VIand SPP written procedures (see Business Practice 70601).

Changes in Process and Assumptions
In order to protect against changes in process and assumptions that could present a significant risk to the completion of the 2015 ITP10, any such changes must be vetted. If a stakeholder group votes on any process steps or assumptions to be used in the study, those assumptions will be used for the 2015 ITP10. Changes to process or assumptions recommended by stakeholders must be approved by the appropriate stakeholder group(s) and the MOPC. This process will allow for changes if they are deemed necessary and critical to the ITP, while also ensuring that changes, and the risks and benefits of those changes, will be fully vetted and discussed.

1SPP.org > Org Groups > Access SPP’s Governing Documents > OATT Business Practices
2015 ITP10 Scope

Approved by ESWG: 10/02/2013
Approved by TWG: 09/18/2013

ESWG / TWG / SPP Staff
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Overview

This document presents the scope and schedule of work for the Integrated Transmission Planning (ITP) 10-Year Assessment. This document will be reviewed by the Transmission Working Group (TWG) and the Economic Studies Working Group (ESWG) beginning May 2013, with the expectation of approvals from the Market Operations and Policy Committee (MOPC) and the Board of Directors (BOD) in October 2013. The assessment begins in July 2013 and is an 18-month study scheduled to be finalized in January 2015.
Objective

The 2015 ITP 10-Year Assessment (ITP10) is a value-based planning approach that will analyze the 10-year out Transmission System and identify 100kV and above solutions to needs stemming from multiple sources: (a) needs identified in the reliability analysis of the 69 kV and above system, (b) needs identified to meet projected renewable policy mandates and goals, (c) needs arising from transmission system congestion, and (d) needs arising from instability of the transmission system. The 2015 ITP10 will be utilized in integrating the 2013 ITP20 with the 100kV and above facilities to incorporate such needs as the following: a) resolving criteria violations; b) mitigating known or foreseeable congestion; c) meeting projected policy mandates and goals; d) improving access to markets; d) the staging of transmission expansion. This assessment is not intended to review each consecutive year in the planning horizon, but only the horizon year.
Stakeholder Process

Working Group Involvement
The 2015 ITP10 will be vetted through the SPP working groups. The ESWG will oversee the economic portions of the 2015 ITP10 and all related data and assumptions. The TWG will oversee the reliability portions of the 2015 ITP10 and all related data and assumptions. The following items will be discussed at the respective working groups:

Regional Cost Allocation Review Task Force (RARTF)
A regional cost allocation review study will be performed in conjunction with the ITP10 process to identify potential project solutions to mitigate Benefit inequities which exist in certain zones. ………

Transmission Working Group (TWG), Model Development Working Group (MDWG)
The TWG and/or the MDWG will be responsible for reviewing the data and results for the following items:

1) Scope
2) Futures - Approval
3) Load Forecast – Peak Demand
4) Steady State Models
5) Constraint Review
6) Reliability Assessment
7) Stability Assessment
8) Transmission Plan Development
9) Benefit Metrics
10) Report

Economic Studies Working Group (ESWG)
The ESWG will be responsible for reviewing the data and results for the following items:

1) Scope
2) Futures – Development and Approval
3) Policy Survey
4) Load Forecast - Energy
Markets and Operations Policy Committee (MOPC)
The MOPC will be sought for endorsement of the following items:
1) Scope
2) Futures
3) Policy-Driven Decisions
4) Metrics
5) Report

Strategic Planning Committee (SPC)
The SPC will be sought for endorsement of the following items:
1) Futures

Seams Steering Committee (SSC)
The SSC will be responsible for the review of the following item:
1) Seams Impacts

Regional State Committee (RSC)
The RSC will be responsible for the following items:
1) Approve Cost Allocation
2) Review the final Report and endorse as appropriate

Board of Directors (BOD)
The BOD will approve the following items:
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1) Transmission Plan

2) Cost and Benefit Allocation

3) Report

The final 2015 ITP10 Report will be approved by the BOD.

**Stakeholder Reviews**

The following is a list of reviews to be provided by stakeholders during the 2015 ITP10 study:

**Load Forecast Review**

Projected peak load per area for the year 2019 and 2024 will be submitted by the modeling contacts for the development of a peak 2019 and 2024 model. Energy per area for 2019 and 2024 will be obtained from publicly available sources and reviewed and updated by stakeholders. Stakeholders will review projected peak load and energy per area. Peak load and energy will also be identified for load serving entities within SPP RTO areas (for example, Hastings Utilities and City of Grand Island load will be reviewed by NPPD).

**Policy Survey**

Stakeholders will provide feedback through a survey, conducted by the ESWG, on current and planned renewable generation plants.

**Generation Resource Plan Review**

ESWG will review the data for all generators added to the model as part of the 2015 ITP10 resource plan. This will include conventional and renewable generation. The review will focus on the siting and capacity of new units. For conventional generation, the zonal demand and capacity figures will be provided, as well as expected capacity margins for 2024. For renewable generation, the siting, capacity, and average capacity factor of each new resource will be provided. This will include resources identified as a part of the Policy Survey and may include renewable resources identified by the resource planning software.

**Economic Model Review**

ESWG will be provided with model data indicating generators and the parameters used in the economic model. Non-confidential parameters such as maximum capacity, ramp rates, O&M costs, etc. will be provided for review. For confidential parameters, such as heat rates, publicly available data will be utilized. However, resource owners may modify the publicly available data to more accurately model their generator’s characteristics as appropriate.

**Constraint Assessment Review**

A list of constraints will be developed to be used in the economic dispatch, as detailed in the Constraint Review Section below. The constraints will be provided to the TWG for review; they will approve the final list of constraints to use, as well as the associated constraint ratings.
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**Power Flow Model Review**

TWG and MDWG will review the economically-dispatched power flow models and provide feedback. The review will focus on the reactive needs.

**Project Development Request**

Stakeholders will be asked to provide suggestions on projects they believe should be analyzed in the study. All stakeholder-submitted project requests will be analyzed to assess the project’s potential to meet needs. This includes reliability, economic, and policy needs as detailed in the Analysis Section of this document.
**Study Process**

1. The futures will be selected and assumptions refined through the various stakeholder groups (ESWG, TWG, MOPC, RSC).

2. The ESWG will oversee the development of the economic models that incorporate the assumptions developed in step #1 above, including review of data and results. Similarly, the TWG will oversee the development of the power flow and stability models used in this analysis, including a summer peak case and an offpeak case. These will be developed through the existing SPP Planning Model Process via the MDWG.

3. Constraints will be developed through the identification of congested facilities and by performing transfer analyses. All constraints will be 100 kV and above facilities for 100 kV and above facility outages within SPP and first-tier neighboring systems.

4. Staff will perform an initial AC analysis using applicable NERC Reliability Standards and SPP Criteria on power flow models that represent the applicable load profiles and generation dispatch associated with each future. The assessments will be limited to the planning horizon year. All facilities 69 kV and above in the models will be monitored within SPP and the first-tier for this analysis as a means to determine 100kV and above solutions for SPP to the problems identified. The TWG will review the results.

5. Concurrently, an economic assessment will be performed to analyze congested facilities on the SPP Transmission System. This will be done using a security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) model over 8,784 consecutive hours.

6. 100kV and above solutions to criteria violations, policy requirements, and/or congested facilities will be identified with input from stakeholders and coordinated as applicable with SPP neighbors. Staff will request suggestions for solutions from stakeholders and perform a preliminary assessment of benefits for these projects. During this phase, Staff will coordinate solutions with the AG and GI Study processes to best accommodate the high-demand areas for the SPP transmission system footprint. Issues identified that are not resolved with 100kV and above solutions will be deferred to ITP Near-Term Assessments for resolution.

7. A check will be performed to determine if projects identified in the 2013 ITP20 will eliminate or defer any projects identified in the 2015 ITP10. This check will be performed by replacing lower voltage solutions with the higher voltage solutions identified in the 2013 ITP20 and re-running the economic and contingency analysis. The economic analysis will include calculating benefit and cost for each alternative.

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8. A follow-up analysis will be performed by Staff repeating the steps above on the identified solutions to validate the solutions and check for any additional criteria violations and/or congested facilities that may have been created.

9. A sensitivity analysis will be performed on the recommended portfolio to assess how versatile the plan is in handling a range of uncertainties.

10. Benefit metrics will be calculated for the recommended portfolio on each future.

11. A 40-year financial analysis will be conducted on the recommended portfolio.

12. Stability analyses will be conducted on the recommended portfolio to determine if voltage stability requirements for the region are met. Dynamic stability analysis will be performed on the Business As Usual Future. A wind transfer voltage stability analysis will be performed on each future.
Data inputs

Economic

The analysis for the 2015 ITP10 will utilize engineering models to facilitate the development of long range transmission plans. One set of models will be the economic models used to produce a market based resource dispatch used in the analysis. These models require certain assumptions regarding generation resources, parameters, and locations (detailed in the following sections). The output of these models will allow engineers to identify the appropriate transmission additions needed from an economic perspective. This output can also be used to determine deliverability of the resources to market used in the analysis.

The major assumptions needed to construct the economic models are detailed below and contain, but are not limited to: market structure, load forecasts, resource forecasts and parameters, transmission topology, renewable assumptions, fuel pricing and availability, etc. Once these assumptions are input into the model, it will perform a security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED).

The following sections detail the parameters to be used in the economic portion of modeling.

Market Structure

SPP anticipates implementing its Integrated Marketplace and Consolidated Balancing Authority (CBA) in March 2014. The Integrated Marketplace and CBA will be baseline assumptions for the analysis.

Futures

Future 1: Business as Usual

This future will include all statutory/regulatory renewable mandates and goals as well as other energy or capacity as identified in the policy survey, load growth projected by load serving entities through the MDWG model development process, and the impacts of existing regulations. This future assumes no major changes to policies that are currently in place.

Future 2: Decreased Base Load Capacity

This future will consider factors that could drive a reduction in existing generation. It will include all assumptions from the Business as Usual future with a decrease in existing base load generation capacity. This future will retire coal units less than 200 MW, reduce hydro capacity 20% across the board, and utilize the Palmer Drought Severity Index for an average of August 1934 and August 2012 to simulate a reduction in existing capacity affected by drought conditions: 10% under moderate, 15% under severe, and 20% under extreme. These target reductions may be adjusted based on locational and operational characteristics within each zone.

Future 3: Increased Input Prices

This future is driven by considering factors that could result in an increase in the price of fuel, for example, more restrictive regulations over shale fracturing and a carbon tax on fossil unit emissions. This future will include all assumptions from the Business as Usual future along with an increase in...
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input prices. It will consider a $36/ton carbon tax and a threefold increase of natural gas prices. As a result of increased input prices, it will also consider a reduction in the rate of load growth of 1% per year.

Load Forecasts

The study will require load forecasts for SPP members and non-members within the SPP footprint, as well as areas outside of the SPP footprint, for the year 2019 and 2024. SPP Staff queries its members through the MDWG for applicable load forecasts to use in each of the zones for the modeling footprint. The base model will also include additional load expected in the SPP region. This load will include a 50/50 forecast from the High Priority Incremental Load Study (HPILS) and will be vetted through the ESWG and the TWG. Energy forecasts will be provided by the ESWG and other contacts. Load shapes will be obtained from publicly available data for the typical load projections and requested from stakeholders for the HIPILS loads. Load shapes will be benchmarked as detailed in the Benchmarking Section.

For load forecasts outside of the SPP footprint, SPP will request load forecasts from SPP tier 1 neighbors. If data is not provided, publicly available data will be utilized as the source of the load forecasts, where available. If unavailable, publicly available information on projected load growth will be extrapolated to develop a representation for load expected in the study timeframe.

Resource Plan

A generation resource plan for 2019 and 2024 will be developed for use in the study for each future. This resource plan will include both renewable and conventional generation. Additionally, new renewable and conventional generation resources will be sited as detailed below.

Each SPP RTO load serving member must meet the current 12% capacity margin requirement outlined in SPP Criteria 2.1.9. The siting of new generation in the resource plan will target a 12% capacity margin for each zone. Capacity needs will be identified for each future for 2019 and 2024.

Renewable generation, for the purposes of this study, includes hydro, wind, solar, and bio-fuel. Designated renewable resources will be identified through the policy survey. Additional renewables will be included in the plans, as needed, to meet the renewable projections, as supplied by the Policy Survey. Additional renewables identified by the resource planning software may also be included. The renewable ownership designations will be reviewed by stakeholders and posted on SPP.org.

SPP tier 1 neighbors will be provided the opportunity to provide feedback and input into the generation resource plan for their area.

System Topology

The focus of the Study is to develop a comprehensive, flexible, and cost-effective transmission expansion plan to meet the requirements of the SPP footprint under various futures.

Power flow models will be required for the Study for both the economic and reliability assessments. The starting point of these power flow models will be the latest MDWG information from Model on Demand™, which includes the current projects from the latest SPP Transmission Expansion Plan (STEP). These power flow models will serve as an input into the economic (production) modeling program to develop a market-based economic dispatch for the system.
Two new DC interconnections, the TresAmigas DC Tie and the Clean Line Plains & Eastern project, will be included in the models for sensitivity analysis only.

**Economic Model Generation**

The generation parameters (Startup cost, operating costs, Min/Max Operating Levels, etc.) will be updated by the ESWG as part of the economic model review.

**Renewables**

Renewable generation, primarily wind, hydro, and solar, operate as energy resources that will require the development of hourly generation profiles for individual plants based on historical data or modeled time-series wind speed datasets. These generation profiles will be time-synchronized with coincident historical load shapes. The economic dispatch model will attempt to realistically model renewable generation curtailment, based on expected market conditions and reliability requirements. A curtailment price consistent with the variable O&M cost will be used to simulate the behavior of the wind generation within the Security Constrained Economic Dispatch (SCED). The ESWG will review the behavior and costs of the renewable generation against appropriate benchmarks.

**Siting**

The expected location of future generation will be considered in areas with appropriate potential. These sites will be further developed and refined as a subset of those selected in the 2013 ITP20 study, as appropriate for the futures of this study. SPP will request that tier 1 neighbors provide siting based on SPP’s identification of capacity needs from the resource plan. If siting is not provided, SPP will site new generation.

**DC Ties and Lines**

DC ties and lines connect SPP to the WECC and ERCOT and Eastern Interconnect systems. Confirmed long-term firm transmission service will be used as a basis for modeling the flow levels of DC ties and lines. Hourly profiles will be developed based on 3-year historical flows on the DC facilities, limited to boundaries of existing long-term firm service commitments. The hourly profiles will be vetted with ESWG and TWG. The cost of energy purchases and sales across the DC ties will be calculated using the hourly average zonal generation locational marginal price of each utility owner multiplied by their ownership share of the output. No curtailment price will be assumed for the long-term firm service profile. For those DC ties or lines with no confirmed long-term firm transmission service, Staff will model no flow across the DC ties and lines.

**Fuel Prices**

Fuel forecasts will be utilized in the resource planning, production cost modeling, and benefit metric calculations. Fuel prices for coal, oil, and uranium, including transportation costs, will be forecasted for the 2024 study year based upon the latest VentyxReferenceCase available at the onset of the study. NYMEX futures will be utilized for natural gas prices, out to the latest year for which the futures are available. For natural gas prices beyond this year, growth rates from the DOE Annual
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Energy Outlook will be utilized. The specific NYMEX and DOE numbers will be developed during the resource planning phase of the study and then locked down for the remainder of the study.

**Environmental Policy**

Emission price forecasts for SO\(_2\), NO\(_x\), and CO\(_2\) for the 2024 study year will be based upon the latest Ventyx Reference Case data available at the onset of the study.

**Policy Survey**

A policy survey will be administered by the ESWG and will be used by stakeholders to provide assumptions regarding specific renewables information. The previous renewables surveys will be used as a reference for development of the current survey. The survey will contain, at a minimum, the following information:

- Name, zone, and capacity for all specific renewable sites that are in-service or expected to be in-service by the end of 2014;
- Renewable energy totals for 2024 and 2019 based on state and utility mandates, goals, and other utility company policy;

For all renewable sites in the models, the renewable energy output for each hour of the year will be based on the maximum capacity provided in the survey. Capacity factors and hourly profiles will be based on expected or historical behavior. Calculations for policy requirements will incorporate stakeholder specific inputs, and capacity factors for wind used in the Study will be based on NREL wind profiles that correspond to a similar location as the wind site and are based on historical weather patterns. **For new wind sited to meet the requirements of the Policy Survey and resource plan, a 15% increase will be applied to the existing capacity factors being utilized for each of the NREL sites.**

**Hurdle Rates**

Hurdle rates will be utilized in the economic model between SPP and neighboring systems to help keep imports and exports at a reasonable exchange levels. Hurdle rates for imports and exports between SPP and other entities will be determined during the benchmarking process.

Hurdle rates between non-SPP entities will be set as needed to model minimal and reasonable exchange between these entities.

**Benchmarking**

After all assumptions and data are included in the economic model, it will be benchmarked against historical system behavior. This benchmarking will be used to assess the reasonability of the simulations.

In order to complete the 2015 ITP10 benchmarking effort, a model will be developed based upon the year 2013. Simulation results from that economic model will be compared with historical statistics and measurements from the SPP real time data, NERC data, and the Energy Information Administration data.
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The ESWG will review the benchmarking data as part of the model review process. Specific benchmarks will include some or all of the following: capacity factor by unit type, generation by unit category, maintenance outages, load shapes, renewable generation profiles, operating, and spinning reserve levels, coal transportation costs, system Locational Marginal Prices (LMPs), flowgate loading, production costs, generation dispatch order, and zonal purchases and sales.

**Steady State**

Being that SPP will implement its Integrated Marketplace and CBA in 2014, powerflow models with a market dispatch under coincident peak load and off-peak load will be developed.

Steady state analysis will be conducted using output from the economic models as a starting reference for load and generation dispatch. These models will be utilized in additional engineering tools in order to conduct an assessment to determine the SPP system’s voltage and thermal impacts. This steady state assessment is detailed in sections below.

**Load**

The load density and distribution for the steady state analysis will be reviewed by the MDWG. Resource obligations will be determined for the footprint taking into consideration what load is industrial, non-scalable type loads and which load grows over time. The MDWG, TWG, and ESWG provide collaborative feedback into the determination of this impact. The load used in the steady state analysis will be the same as that used in the economic model as described in Section: Load Forecast.

**Generation Resources**

The generating resources determined through Section A.III: Resource Plan will be added to the power flow. Each future will contain a different subset of generation resources and correspond to a unique power flow case. These generating resources will be reviewed by the ESWG and will correspond to the economic analysis conducted for the Study.

**Steady-State System Topology**

The topology used in the steady state analysis will be the same as that used in the economic model as described in Section: System Topology.

**Exports/Imports to First Tier**

The exports/imports used in the steady state analysis between SPP and neighboring AC systems will be determined by the economic dispatch model. Exports and imports between DC interconnections will be based on historical hourly scheduling of long-term firm transmission service. This economic exchange of energy between neighboring systems will be modeled for the steady state analysis.
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**Market Dispatch**

The economic models will be used to determine hourly load profiles and generation dispatch for the steady state analysis. The generation dispatch and corresponding hourly profiles will be mapped from the economic model to the reliability power flow model.
**Analysis**

**Define Constraints**

To identify which constraints are applicable in 2024, Staff will begin by reviewing the existing NERC Book of Flowgates (BoF) to determine additions or deletions from the list of constraints (event file) for the economic model. Staff will perform additional analysis using Power Analytics and Trading Tool (PAT) to identify the top constraints by congestion costs (average shadow price times the number of constrained hours) on the system for 8,784 hours. These additional constraints will be reviewed and approved by TWG. The following items will be considered in the analysis:

- The initial constraint list will be the then-current BoF
- Constraints studies will be run over 8,784 hours (1 year)
- This analysis will use the 2024 economic model(s) for each future
- Contingencies 100 kV and above in SPP and first-tier
- Monitored elements 100 kV and above in SPP and first-tier
- Unless other information is available, each constraint’s rating will be selected based upon the applicable Rating A (normal rating) or Rating B (emergency rating) in the power flow model.

**Needs Assessments**

The reliability, policy, and economic needs of the system will be identified in each future in order to develop a transmission portfolio for each future. Each analysis will be performed in parallel to determine all needs across the system in 2024. All needs identified in the assessments below will be evaluated by Staff for potential consideration in the interregional planning process pursuant to the requirements of Order 1000.

**Economic Assessment**

The economic needs of the system will be identified in each future in order to develop a portfolio for each future. All of the system needs will be identified through the use of a SCUC & SCED simulation that accounts for 8,784 hours representing each hour of the year 2024.

The SCED will determine nodal Locational Marginal Prices (LMPs) while dispatching the generation economically. The LMPs, among other cost components, reflect the congestion occurring on the power grid’s binding constraints. System congestion will be identified in each of the 8,784 hours. A list of binding constraints will be developed for each future and ranked based upon the average shadow price associated with each constraint. The top twenty constraints based upon this ranking will be identified as economic needs, subject to ESWG review.

**Policy Assessment**

The policy needs of the system will also be identified for each future in order to develop a portfolio for each future. All of the system needs will be identified through the use of a SCUC & SCED
simulation that accounts for 8,784 hours representing each hour of the year 2024. Renewable generation may experience the effects of congestion and be curtailed by the SCED. Shortfall in the achievement of the renewable requirements of each future due to this curtailment will be identified. Renewable resources that experience an annual energy output of less than the statutory/regulatory mandate or goal will be identified as policy needs. The required energy is based on maximum capacity, capacity factor, and generation profile.

**Steady State Assessment**

The steady state assessment will use 2024 summer peak and high wind with low load (off peak) models based on a market dispatch. Each future will be evaluated for the same peak and off peak hours. An N-1 contingency analysis will be conducted on each future for the peak and off peak cases. All SPP and first tier facilities 69 kV and above will be monitored for this analysis in development of 100 kV and above solutions.

The non-converged contingencies will be reviewed.

**Stability Assessment**

Dynamic stability analysis will be conducted on the final recommended portfolio for the Business as Usual future to assess transient voltage recovery. It will be conducted on the offpeak model simulating the 2013 TPL Category B and C contingencies identified by members and additional contingencies identified by Staff through the Fast Fault Screening tool. TWG will review and approve Staff identified contingencies for further analysis.

A voltage stability assessment will be conducted on each future using the recommended final portfolio to assess the transfer limit (MW) due to transfer of wind west to east across the SPP footprint. These must be determined by examining voltage performance during power transfer into a load area or across an interface. The stability assessment consists of a wind dispatch analysis to determine if the dispatched wind generation in the 2015 ITP10 2024 summer peak models in all futures can be dispatched without the occurrence of voltage collapse or thermal violations.

**Solution Development**

Staff will solicit stakeholders for possible solutions to the needs. A pool of possible solutions will be used to mitigate the economic, reliability, and policy needs in creating the 2015 ITP10 transmission plan. This pool of solutions will come from transmission service studies, generation interconnection studies, previous ITP studies, and stakeholder input. Solutions developed could meet more than one need (i.e. economic, policy, and/or reliability needs) and will be classified as project types based on the criteria outlined below. To the extent benefit to cost deficient zones are identified remedies are recommended as a result of the Regional Cost Allocation Review, project remedies will be evaluated and recommended by Staff, in coordination with the deficient zones and appropriate stakeholder groups, as part of the 2015 ITP10 analysis as appropriate.

Based on the criteria below, Staff will develop a plan for each future. Staff will then consolidate the projects from each future into a recommended plan.
Economic Project Solutions

Economic projects will be developed and evaluated based upon how well they mitigate congestion. Any economic project with a one-year B/C ratio of 0.9 or greater will be included for further evaluation.

Economic seams projects will be initially evaluated and considered under the assumption that the project would be cost shared with an SPP neighbor, with SPP paying for 80% of the cost and the neighbor paying 20% of the cost. As the evaluation progresses and the SPP neighbor identifies the level with which the transmission project benefits them, then the cost percentages should be updated to a more accurate reflection of the benefit distribution.

Policy Project Solutions

Policy projects will be developed and evaluated based upon how well they mitigate curtailment of renewable energy required by the regulatory/statutory mandates and goals as defined by the 2015 ITP10 policy survey. Any policy project that helps to mitigate curtailment of renewable requirements will be included for further evaluation.

Reliability Project Solutions

Reliability projects will be developed and evaluated based upon how well they mitigate member criteria violations for the peak and offpeak hours.

Interregional Considerations

Seams projects will be considered as part of the 2015 ITP10 study and expansion plan as potential solutions, and SPP will collaborate with neighboring entities regarding the identified needs, benefits, potential solutions, and costs. For the neighbors that SPP has an agreement with, joint coordination will be done in accordance with that agreement.

Final Recommended Portfolio

[This section was left blank intentionally. A final decision regarding portfolio recommendation will be made after the accomplishment of the MOPC Action Item #223 by April 2014].

Reliability, policy, and economic solutions will be grouped together and refined to create a portfolio for each future. The grouping of projects will be evaluated for redundancies. If, for example, a reliability project is similar to a policy project, the two projects will be evaluated to see which project meets both the reliability need and the policy need in the most cost effective way, while the other project is then discarded.

Each future’s portfolios will be consolidated into a single recommended portfolio. The projects will be consolidated across futures based on the weightings below:

| Portfolio | Weighting |
Forty-Year Financial Analysis

The 2015 ITP10 shall assess the cost effectiveness of the recommended portfolio over a forty-year time horizon in accordance with Section III.3.c of Attachment O of the SPP OATT. To estimate the benefits over 40 years, Adjusted Production Cost (APC) savings will be calculated for the two model years developed, 2019 and 2024. The slope between the selected points will be used to extrapolate the benefits beyond 2024 over a 40 year timeframe. The costs will be calculated using the formula for Annual Transmission Revenue Requirement (ATRR). The total benefits and costs will be reported in net present value (NPV) dollars.

Benefit and impact calculations will be made on a Regional, Zonal, and State basis. State values will be extrapolated from the zonal costs and benefits. Many zones are only in one state. For those zones that are only in one state, their full portion of both costs and benefits will be allocated to the state. For zones crossing state borders, their portion of both costs and benefits will be allocated to each state based on their percentage of load that is in each state.

Net benefits and B/C ratios will be calculated based on NPV benefit and NPV cost and will be reported based on present dollars (2014).

Benefit Metric Development and Usage

The metrics used to measure the value of the final portfolio in the 2015 ITP10 are identified here and will be vetted with the ESWG. These metrics will be used to measure the value of the final consolidated portfolio on each future.

<table>
<thead>
<tr>
<th>Metric Description</th>
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<tbody>
<tr>
<td>APC Savings</td>
</tr>
<tr>
<td>Value of Replacing Previously Approved Projects</td>
</tr>
<tr>
<td>Reduced Losses</td>
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<tr>
<td>Reduced Capacity Costs</td>
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<tr>
<td>Reduction of Emissions Rates and Values</td>
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<tr>
<td>Public Policy Benefits</td>
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<tr>
<td>Assumed Benefit of Mandated Reliability Projects</td>
</tr>
<tr>
<td>Mitigation of Transmission Outage Costs</td>
</tr>
</tbody>
</table>

Table 1: Monetized Cost Benefit Metrics for 2015 ITP10
To the extent that any adjustments or changes to Benefit Metrics are recommended by the Regional Allocation Review Task Force (RARTF), these changes will be considered by the ESWG.

**Sensitivities**

Sensitivities will be conducted on the final recommended portfolio for the Business as Usual future to assess how versatile the plan is in handling a range of uncertainties. Economic analysis will be performed for the sensitivities. The following sensitivities will be performed:

- Natural Gas Price
- Demand levels
- TresAmigas and Clean Line Plains & Eastern

Specifics of the DC project sensitivities will be developed and approved by the ESWG.

The sensitivities will be used to measure the viability of the proposed transmission plan that is produced through the 2015 ITP10. These sensitivities will not be used to develop the transmission projects or filter out projects.

**Staging**

A project implementation plan will be developed for the final recommended portfolio. The final portfolio will be structured such that each element can be implemented in a staged manner as actual system developments approach the assumptions resulting in the need for that element. To help stage the projects SPP will utilize years 2019 and 2024. This section is broken into two parts: one for projects classified to meet one set of needs (i.e. economic, policy, or reliability needs); one for projects meeting multiple needs.

**Single Project Classification**

For economic projects in Future 1, Staff will stage projects based on linear interpolation of B/C ratios from 2019 to 2024 with consideration of lead times. For economic projects in Future 2 and Future 3, Staff will stage them with a 2024 need date.

For policy projects, Staff will stage projects in order to meet the renewable requirements.

For reliability projects in Future 1, Staff will stage projects based on linear interpolation of thermal loadings from 2019 to 2024. All other reliability projects in Future 1 will be staged with a 2024 need date. For reliability projects in Future 2 and Future 3, Staff will stage them with a 2024 need date.

**Multiple Project Classification**

If a project is classified as more than solely economic, policy, or reliability project, the project will be staged to meet the earliest need date established through the Single Project Classification Section with a requirement that for economic projects, the one-year B/C ratio threshold crosses 1.0.
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**Reactive Needs**

If any 300 kV and above upgrades are identified as solutions in the portfolio, line-end reactive requirements analysis will be performed for the new transmission lines greater than 300 kV system to provide an indicative amount of reactor needs before design level studies are completed.

**Final Reliability Assessment**

A steady state N-1 contingency analysis will be conducted to identify any remaining outstanding issues on the final recommended portfolio.

**Cost Estimates**

The cost estimates used for projects that are tested in the initial project development phase will be Conceptual Estimates as defined by the SPP Business Practice 7060. The Conceptual Estimates will be developed by Staff and utilize standardized estimates and multipliers that are based on historical data. Projects that pass the initial screening phase will be designated for Study Estimates as defined by Business Practice 7060.

A Study Estimate will be prepared by the designated TO(s) for non-competitive upgrades and by Staff for competitive upgrades by completing a Standardized Cost Estimate Reporting Template (SCERT) for all upgrades that are required to complete that project. The Study Estimate will provide a more refined cost estimate for potential project approval. For all Study Estimates, Staff will provide TO’s a minimum of six weeks from the date of request before the estimate is due.
### Timeline

The 2015 ITP10 will generally follow the process flow below beginning in July 2013 with final results in January 2015. The estimated timeline is as follows:

<table>
<thead>
<tr>
<th>2015ITP10</th>
<th>Group(s) to review/endorse</th>
<th>Start Date</th>
<th>Completion Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Futures &amp; Scope</td>
<td>ESWG, TWG</td>
<td>April 2013</td>
<td>October 2013</td>
</tr>
<tr>
<td>Policy Survey</td>
<td>ESWG</td>
<td>May 2013</td>
<td>August 2013</td>
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<tr>
<td>Load Forecast and Generation Review</td>
<td>ESWG, TWG</td>
<td>May 2013</td>
<td>August 2013</td>
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<td>Economic Model Development &amp; Review</td>
<td>ESWG</td>
<td>May 2013</td>
<td>December 2013</td>
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<td>Model Benchmarking</td>
<td>ESWG</td>
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<tr>
<td>Constraint Review</td>
<td>TWG</td>
<td>November 2013</td>
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<td>Economically-dispatched Powerflow Model Development &amp; Review</td>
<td>TWG</td>
<td>January 2014</td>
<td>April 2014</td>
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<td>Reliability, Policy, Economic Needs Assessment</td>
<td>ESWG, TWG</td>
<td>February 2014</td>
<td>April 2014</td>
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<td><strong>Finalize benefits metrics and allocation methods for ITP10 portfolio analysis</strong></td>
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<td>Review draft report with recommended solutions</td>
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10-Year Assessment Process (Initiated Every 3 Years)

Coordinate with Stakeholders to Implement Previous ITP

Scenarios Narrowed Fewer Scenarios More Models

Stakeholder Approval of Study Scope Document ESWG/TWG

Model Development Will go through ESWG/TWG

Define Additional Flowgates Monitor All Facilities, Outage 100kV+

Security Constrained Unit Commitment and Economic Dispatch (SCUC & ED) Analysis

Perform Applicable AC Contingency Analysis

Develop Solutions to Congestion and/or Criteria Violations, Coordinate with AG/GI, and Compare Alternatives 100kV+

Receive 20 Year Assessment Solutions

Determine if 20-Year Projects Solve Problems

Validate Solutions and Check for Additional Issues by Repeating Analysis Perform Stability Analysis

Cost Benefit for Identified Projects/Interactions 345kV+

Stakeholder Review & BOD Approvals

Year 2

July

December

January

Year 3

June

January
**Deliverables**

**Final Report and Recommended Portfolio**

The results from the 2015 ITP10 will be compiled into a report detailing the findings and recommendations of SPP Staff. The report will include a project list identifying each upgrade. This report will also be incorporated into the 2015 STEP Report.

**Staging and Timing of Project Implementation**

A project implementation plan will be developed for the recommended transmission plan. The final plan will be structured such that each element can be implemented in a staged manner as actual system developments approach the assumptions resulting in the need for that element. Each element will have at least one of the following justifications: policy, economic or reliability justification. NTCs/NTC-Cswill be issued for the 2015 ITP10 plan elements in accordance with the Tariff, Attachment O, Section VI and SPP written procedures (see Business Practice 70601).

**Changes in Process and Assumptions**

In order to protect against changes in process and assumptions that could present a significant risk to the completion of the 2015 ITP10, any such changes must be vetted. If a stakeholder group votes on any process steps or assumptions to be used in the study, those assumptions will be used for the 2015 ITP10. Changes to process or assumptions recommended by stakeholders must be approved by the appropriate stakeholder group(s) and the MOPC. This process will allow for changes if they are deemed necessary and critical to the ITP, while also ensuring that changes, and the risks and benefits of those changes, will be fully vetted and discussed.

---

1 [SPP.org > Org Groups > Access SPP’s Governing Documents > OATT Business Practices](http://SPP.org)
**Recommendation:**

**RECOMMENDATION APPROVED:**  
YES  
78.6%

Enter a *“1”* in the voting column

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**Percentage Approving:**

100.00%

**For SPP membership as of:**

8/9/2013

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**Load Weighted Vote:**

69.8%
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**Percentage Approving:** 57.14%
AEP’S ALTERNATIVE TO FUTURE 3
C. RICHARD ROSS

THE MERITS OF FUTURE 3

- It is not needed.
- The fact that the development of Future 3 required such extreme assumptions in order to reach a case that was significantly different indicates the other Futures are representative of a wide range of expected and likely outcomes.
- Future 3’s assumptions and the resulting resource plan are not going to provide guidance that should be used to materially impact the construction plan.
- If Future 3 is continued, its analysis should be abbreviated substantially so that the required effort by SPP Staff; Members Staff and the expense of outside consultants is minimized and aligned with the insight/benefit to be gained from the study.
  - This can best be achieved by not running the case.
  - In the alternative, SPP could run the case to identify needs without developing solutions.
A Better Idea (N-1-1)

- Let’s look at the realistic cases and resulting plans we have, from Future 1 & 2, to see what we can do to make them more resilient.
  - The cases to date have focused starting with a system intact and given less consideration to the system under maintenance conditions.
  - The system must be operated 8760.
  - The system must be maintained, so during off peak periods something somewhere is almost always out for maintenance.
  - Maintenance outages are not “contingencies,” because SPP has the chance to change dispatch & commitment to return the system to a secure state. However, a secure state may not be possible & hence we need to study the situation further to see if reliability system improvements are appropriate.

- Let’s expand the analysis on Futures 1 & 2 by conducting an additional review of off-peak and maintenance outage conditions on the system.

N-1-1, What Specifically Are We Suggesting?

- Identify significant outages that would adversely impact the system. (AEP has done this)
- Remove those facilities from the system & redispatch to create a new base case (N-1 case)
- This would focus on potential reliability issues and would not necessarily be a full blown economic study. For this reason, a security constrained redispatch (SCRD) can be utilized for the maintenance adjustments such that a new SCED is not required.
- Perform the contingency analysis on this new case. Given this new base N-1 case already includes one outage, the contingency analysis then becomes an N-1-1 study.
- This N-1-1 study is similar to analysis performed in during the development of expansion plans in other regions.
**WHY?**

- This is a logical extension of the TPL standards study SPP is already required to perform.
- Including it in this manner will *integrate* that activity into our Integrated Transmission Planning process so that, should future problems be identified, we can address the requirement during the planning process.
- Conducting the study in this manner may mitigate the need for the separate TPL study work allowing the staff’s work to be more effective & efficient.
- “Win Win”

**POSSIBLE AREAS OF CRITIQUE:**

- There is not enough wind in Future 1 & Future 2.
- We have not fully considered the range of scenarios contemplated in the Bridge Study.
- May require SPP to purchase new technical software.
- Not all Members perform maintenance at the same time.
MOPC Report to Board of Directors / Members Committee

October 29, 2013
Rob Janssen - Chair

Agenda

• Action Items
  – RTWG – TRR104, 110
  – MWG – MPRR130, 145
  – ESWG – 2015 ITP 10 Scope

• Information Items
  – BPWG – GI Improvements and ATSS Backlog Clearing
  – PCWG – Project Cost Monitoring
  – RARTF – Report Review
  – TWG – HPILS
  – TWG – 2014 ITPNT
  – RTWG – Integrated Marketplace Compliance
Action Items Overview

• Order 1000 Compliance Tariff Changes
  – FERC issued its Order in July 2013; Compliance filing due date is November 17, 2013
  – RTWG developed TRRs 104 and 110 as compliance response
  – TRR 104 was approved unanimously at MOPC
  – TRR 110 was modified by MOPC to reduce bid deposit from $50,000 to $10,000 and approved unanimously
  – Modification with reviewed with SPC, which did not endorse the change
  – Staff will present alternative recommendation after MOPC / RTWG presentation on TRR 110
Action Items Overview

- Integrated Marketplace Protocol Revisions
  - MOPC approved numerous protocol revisions during its Oct 2013 meeting
  - MPRRs 130 (Must Offer) and 145 (Capacity Requirements) were debated during the meeting and approved with either objections or substantive modifications, respectively

Action Items Overview

- 2015 ITP 10 Scope
  - ESWG developed three separate futures for the 2015 ITP 10 study scope in an attempt to include in the planning process strategic futures identified by the SPC
  - During its July 2013 meeting, MOPC did not approve the third future proposed for the 2015 ITP 10 study scope
  - The Board directed Staff and the MOPC / ESWG to continue developing the Resource Plans for all three futures for the 2015 ITP 10 study, subject to further review
Action Items Overview

• 2015 ITP 10 Scope – Further Review
  – After further development, the ESWG presented the Resource Plans to MOPC during its October 2013 meeting and requested approval of the 2015 ITP 10 scope document, which included all three futures
  – MOPC approved the 2015 ITP 10 scope with several modifications, including the removal of the third future
  – Alternative to third future will be presented to Board by Member representative in response to further discussions at MOPC and SPC following MOPC vote
Order 1000 Compliance Tariff Changes

- FERC issued its Order in July
  - Filing due date is November 17, 2013
- FERC accepted in part, and denied in part, the filing
- Staff identified 25 areas requiring changes or further explanation
  - 9 proscriptive changes
  - 12 SPCTF changes
  - Additional Explanations

- SPP must file Tariff changes even for those areas for which rehearing has been requested

Proscriptive Changes (TRR104)

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<tr>
<td>Byway Projects</td>
<td>Include in TOSP</td>
<td>Revised Attach. Y</td>
<td>150,153</td>
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<td>Right of Way</td>
<td>Remove ROW control as ROFR</td>
<td>Attach. Y I.1 (c) Add to TOSP</td>
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<td>Applicable Law</td>
<td>Remove reference to “Applicable law” From qualification</td>
<td>Attach. Y I.1(d) Add to TOSP</td>
<td>178-180</td>
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<td>Meeting NERC Criteria</td>
<td>Change “ability to meet” to “how it plans to meet”</td>
<td>Attach. Y III.1.b.5</td>
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<td>State Approval</td>
<td>Remove requirement to demonstrate ability to comply with applicable law</td>
<td>Attach. Y III.1.b.iii.5 Add to TOSP</td>
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<td>Financial Strength</td>
<td>Remove ability of an incumbent to qualify by simply being the incumbent</td>
<td>Attach. Y III.2.c.vi.4</td>
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<td>Project Re-evaluation</td>
<td>Supply reference to cost bandwidth in business practices in Tariff</td>
<td>Attach. Y VI.3</td>
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<td>Significant Delay</td>
<td>Add criteria to Tariff as to what constitutes a “Significant Delay”</td>
<td>Attach. Y VI.4</td>
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<td>Merchant Transmission</td>
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<td>Addendum 5</td>
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TRR110

Tariff Changes directed from the SPCTF

TRR110 – Tariff Changes by the SPCTF

- Right of Way control [removed from Qualification TRR104]
  - Added more detail to Project Management grading [Attach Y III.2.f.iii(2)]
- Applicable Law [Removed from Qualification-TRR104]
  - Added requirement to Project Management Section requiring QTO to submit if is authorized to construct in the state and if it has a state ROFR [Attach Y III.2.f.iii(2)]
- Add definition of “Local Projects” (cite 180)
  - New definition follows Order 1000 [Attach Y Section II]
- Add definition of “Rebuild” (cite 184)
  - FERC directed to add definition consistent with the one SPP supplied in an answer [Attach. Y Section II]
TRR110 – Tariff Changes by the SPCTF (2)

- Clarify how SPP will classify a project that is a combination of “rebuilt” and new facilities (cite 184)
  - Project is a Rebuild if 80% or more of the total cost is a Rebuild
  - Otherwise, the project is split into different segments representing that portion that is a Rebuild (ROFR) vs. new facilities (TOSP)
- [Attach. Y I.2]

- Reliability Exception (Short-Term Reliability Projects, STRP) (cite 195-199) [Attach Y I.3]
  - To maintain a ROFR for new Reliability projects it must meet:
    - Needed within 3 years to solve a reliability criteria
    - SPP must post for each project its ID and explanation of violation
    - SPP must post why violation was not identified earlier
    - Permit stakeholders 30 days to comment
    - SPP must maintain a list of approved STRP on web site and file at FERC annually

TRR110 – Tariff Changes by the SPCTF (3)

- Remove requirement to have executed contracts for an entity to qualify to bid on a project as part of the initial qualification process (cite 227) [Attach Y III.1.b.iii]
  - Changed to have the entity describe how it plans on satisfying the managerial criteria
- RFP Proposal deposit – Must state a specific amount or a formula on how SPP plans to calculate the cost (cite 243-244)
  - Set deposit at $50,000 per RFP proposal
  - Further clarified that the actual cost shall be allocated to each proposal
  - Deposit shall be held in escrow and any refund shall be at the accrued interest rate
  - Costs shall be related to the administrative cost of evaluating the RFP Proposals
TRR110 – Tariff Changes by the SPCTF (4)

- Add details defining the requirements to meet the firm capital commitment requirements (cite 288-289) [Attach Y III.2.d.vii]
  - Finance Committee had already addressed this issue, it original intent was to have the requirements in a business practice.
- Impacts on third parties [Attach. O V.7]
  - As part of the SPP planning process, it must notify third parties of potential impacts to their network due to upgrades in SPP
  - Determine if SPP will pay for any such upgrades
    - SPCTF decided not to fund them
    - Concurrency from CAWG
  - Will follow any JOA with the third party
- Public Policy Requirements [Attach. O]
  - Added requirement to post timeline identifying when stakeholders to provide input [Section III.1, III.4, III.5 and III.6]
  - Clarifying the identification of Public Policy Requirements in the Scope development [Section III.7]

Areas with no Tariff Changes

- Several areas FERC allowed SPP to file additional explanations rather than Tariff changes
  - Why a non-member entity wanting to become a QRP must pay the $6,000 fee
  - Why SPP chose the point weighting complies with the requirements of Order 1000
  - Why the Industry Expert Panel would recommend a proposal to the BOD if it was not the highest score
- In addition, SPP has filed for a one year extension to include upgrades from the ATSS process
  - This was not contemplated by anyone and can have a major impacts to the ATSS
MOPC Recommendation

• The Board of Directors approve Tariff Revision Requests TRR’s 104 & 110.

• MOPC’s motion included a change for the deposit in TRR 110 from $50,000 to $10,000.

• MOPC approved unanimously with 4 abstentions (Exelon, City of Coffeyville, Southwestern Public Service, OPPD)

• Approved by the RTWG on Sept. 25
MPRR130 – Must Offer Penalty Calculation and Rules

Background

– The must offer design that was filed in February 2013 lacked detail related to non-compliance and the penalty calculation

– MPRR130 design:
  ▪ Defines the criteria for non-compliance
  ▪ Defines the penalty calculation in detail
  ▪ Defines the distribution and assessment of the penalty
  ▪ Moves the must offer requirement from Market Participant to Asset Owner

Design Elements

1. A market-wide check is done.
   a) If the DA Market clears w/o curtailing fixed Demand Bids, fixed Exports, and OR requirements [Protocols 4.3.1.2(1)(a)(i)], then no penalty will be assessed

2. If an AO offers all Resources not on outage with a commitment status of Market or Self, then no penalty will be assessed

3. If an AO has a Resource in Reliability or Not Participating status, but offers enough to cover OR, fixed firm Exports, 90% of Reported Load, then no penalty will be assessed

4. If an AO does not offer enough, firm power purchases, sales and purchase power agreements will be considered

5. If an AO does not offer enough to cover OR, fixed firm Exports, 90% of Reported Load, then a penalty will be assessed
MOPC Recommendation

- The Board of Directors approve Marketplace Protocol Revision Request 130.

- Working Group Voting Results
  - MWG approved on September 3, 2013
  - RTWG approved with modifications on September 11, 2013
  - ORWG approved on September 12, 2013
  - MWG approved RTWG modifications on September 17, 2013

- MOPC approved MPRR130 with 5 No votes (KGE, SPS, Exelon, Westar, and Prairie Wind) and 4 abstentions (ITC Great Plains, KPP, KEPCo, City of Coffeyville)

MPRR 145 – Head-room & Floor-room Capacity Requirements

Background

- Head-Room and Floor-Room Requirements are needed to ensure reliable dispatch in real-time
- Head-Room and Floor-Room represent capacity required above average hourly energy for intra-hour load changes
- Instantaneous needs may be greater than (Head-Room Requirement) or less than (Floor-Room Requirement) average hourly load
MPRR 145 – Head-room & Floor-room Capacity Requirements

Design Elements

- Programmatically calculated for each hour of the Operating Day
  - Day-Ahead Market uses 0% of Calculated Head-room & Floor-room (MPRR needs to be corrected)
- Can be adjusted as needed using adjustment multipliers as operational needs dictate
- Quarterly report will be given to MWG on Head-room & Floor-room

MOPC Recommendation

- The Board of Directors approve Marketplace Protocol Revision Request 145.
- Working Group Voting Results
  - MWG approved on September 18, 2013
  - RTWG approved with minor modifications on September 25, 2013
  - ORWG approved on October 1, 2013
- MOPC approved with 7 abstentions (ITC Great Plains, Flat Ridge 2, NPPD, NextEra, Dogwood, City of Coffeyville, Exelon)
2015 ITP10 Resource Plan

• Developed to identify additional resources needed to meet renewable policy survey requirements and serve future load
• Serves as input to the economic model used for transmission analysis
• Presenting resource plans for all 3 futures – as directed by BOD from July meeting
  – 2019 and 2024
  – Siting plan yet to be developed
  – Approved by ESWG October 15th

2015 ITP10 Futures

• Future 1: Business as Usual
• Future 2: Decreased Base Load Capacity
  – Up to 20% capacity reduction of conventional generation and hydro
  – Most coal units under 200 MW retired
• Future 3: Increased Input Prices
  – Natural gas prices tripled
  – Carbon tax
  – Demand Response/Energy Efficiency
  – 2.8 GW peak load reduction compared with Futures 1 and 2
Policy Survey Resource Plan

- Policy Survey approved by ESWG on August 20th
- Renewable resource plan developed to address unmet renewable survey requirements including policy mandates and goals and other non-policy submissions
  - 2.2 GW of renewables added
  - Added renewables included in resource plans for all three futures

Renewable Capacity Additions by Utility - 2024

- Expected to be online by end of year 2014
Resource Plan Simulations

- Generation expansion plan developed for each of 3 sub-regions for each Future
- Constraints
  - Zonal load requirements
  - Zonal generation capacity
  - Zonal capacity margin requirement (12%)
- Units allocated to zones within the sub-region based on zonal capacity needs

Resource Plan Sub-regions*

* Not the same as Tariff defined Sub-regions
Future 1 Resource Additions through 2024*

Total F1 Capacity Additions: 13.4 GW

- South: 26, 11 units
- KSMO: 14 units
- Nebraska: 3 units

*Does not include policy survey resource additions

Future 2 Resource Additions through 2024*

Total F2 Capacity Additions: 18.8 GW

- South: 28, 13 units
- KSMO: 24 units
- Nebraska: 9 units

*Does not include policy survey resource additions
Future 3 Additions through 2024*

Total F3 Capacity Additions: 19.5 GW

Total F3 Wind Additions: 8.7 GW

This wind is economic (not related to Policy Survey)

*Does not include policy survey resource additions

Future 1 Capacity Additions By Zone - 2024
Future 2 Capacity Additions By Zone - 2024

Future 3 (No Coal*) Capacity Additions By Zone - 2024

*Recommended by ESWG
Resource Plan Status

- Approved by ESWG October 15\textsuperscript{th}
- MOPC voted to eliminate third future October 16\textsuperscript{th}

2015 ITP10 SCOPE
2015 ITP10 Scope Overview

• Futures
• HPILS Loads and NTC Modeling
• Consolidation
• Sensitivity Analysis
• Stability Analysis
• Seams Coordination

HPILS Loads and NTC Modeling

• Base case modeling assumptions
  – Include HPILS loads and HPILS NTCs
  – Load forecast assumes 50/50
Consolidation

- MOPC removed from Scope to be considered by ESWG and MOPC later

Sensitivity Analysis

- Natural gas prices
- Demand
- HVDC
  - Tres Amigas HVDC tie
  - Clean Line Plains and Eastern HVDC line
Stability Analysis

- Stability assessments* recommended by TWG
  - Voltage stability assessment
  - Dynamic stability
- Expected value:
  - Assess stability of Final Recommended Portfolio
  - Checks the final portfolio does not cause adverse impacts to system stability
  - Compliant with Criteria 3.5 and NERC Standards
- Expected incremental cost
  - $30k

*Scope of assessment exceeds budget

Seams Coordination

- Seams projects will be considered as part of the study
- SPP will collaborate with neighboring entities regarding the identified needs, benefits, potential solutions, and costs
- If JOA is in place, joint coordination will be done in accordance with the agreement
- SPP Staff is coordinating with neighboring entities on modeling and input assumptions
Stakeholder Feedback

• The TWG and ESWG approved the 2015 ITP10 Scope (containing all three futures).
  – TWG unopposed, September 18th
  – ESWG unopposed, October 2nd

MOPC Recommendation

• The Board of Directors approve the 2015 ITP10 Resource Plan as modified: Delete Future 3 and Staff move forward with Futures 1 & 2; Delete the Final Portfolio Consolidation Section
  – Note: The Board materials include modifications that were not in the MOPC-approved version on pages 7 and 21 of the document

• The motion was approved by MOPC in a Roll Call vote of 78.6%.
Information Items Overview

- **BPWG – GI Improvements and ATSS Backlog Clearing**
  - Generation Interconnection improvements tariff approved by MOPC and included in Board’s Consent Agenda
  - Aggregate Study Backlog Clearing Process approved by FERC and implemented on 2011-AG3 study process

- **PCWG – Project Cost Monitoring**
  - Expanding review to all Legacy Projects with in-service dates after Jan 1, 2014; Business Practice modifications to be developed to implement that change
Information Items Overview

• RARTF – Report Review
  – MOPC undertook significant discussion of the Report and its potential implementation; Approved Report as being consistent with Tariff requirements

• TWG – HPILS
  – Received update on study; Expect preliminary reliability results and recommendations to TWG in mid-November

• TWG – 2014 ITPNT
  – Reviewed Draft Portfolio results; Study on track

• RTWG – Integrated Marketplace Compliance
  – Nov 4, 2013 MOPC and BOD/MC meetings scheduled

BPWG
Generator Interconnection Improvements

- BPWG made changes to white paper since previous approval, including returning the study process time frame from 120 to 180 days as a result of a request from the TWG
- The white paper, including all changes, was approved by the MOPC
- TRR 107, which was based on the 120 day time frame, was approved, subject to modification from the 120 to the 180 day study process prior to filing

Backlog Clearing Process

- FERC Conditionally Accepted the tariff revisions effective Oct 12, 2013, compliance filing due Nov 12, 2013
- Add additional tariff language to clarify calculation of Make-Whole payments and Cost Reallocation
- Because of late drop-out requests in 2011-AG3 it will be the first to which this process applies
- Aggregate Study Completion Agreements have been send and deadline to return is Nov 1, 2013
PCWG

MOPC Action Item 214

PCWG to have further discussion on the monitoring process of the Legacy Projects Procedure (BP 7050) for costs that change over longer than the time frame of a quarter and bring back to MOPC in October
### Legacy Projects with In-Service Date after 12/31/2013 by PO

<table>
<thead>
<tr>
<th>Project Owner</th>
<th>Projects</th>
<th>Upgrades</th>
<th>Latest Cost Estimate</th>
<th>% of Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>8</td>
<td>16</td>
<td>$313,200,800</td>
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<tr>
<td>Empire</td>
<td>1</td>
<td>1</td>
<td>$1,500,000</td>
<td>0.1%</td>
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<tr>
<td>GMO/KCPL</td>
<td>2</td>
<td>5</td>
<td>$449,040,000</td>
<td>19.0%</td>
</tr>
<tr>
<td>ITCGP</td>
<td>1</td>
<td>6</td>
<td>$285,024,557</td>
<td>12.0%</td>
</tr>
<tr>
<td>Mid-Kansas</td>
<td>4</td>
<td>4</td>
<td>$28,975,130</td>
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<tr>
<td>NPPD</td>
<td>1</td>
<td>1</td>
<td>$5,645,881</td>
<td>0.2%</td>
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<tr>
<td>OGE</td>
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<td>14</td>
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<td>OPD</td>
<td>1</td>
<td>1</td>
<td>$19,796,666</td>
<td>0.8%</td>
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<tr>
<td>Prairie Wind</td>
<td>1</td>
<td>2</td>
<td>$50,500,000</td>
<td>2.1%</td>
</tr>
<tr>
<td>SPS</td>
<td>15</td>
<td>34</td>
<td>$438,113,353</td>
<td>18.5%</td>
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<tr>
<td>Western Farmers</td>
<td>14</td>
<td>19</td>
<td>$58,690,500</td>
<td>2.5%</td>
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<tr>
<td>Westar</td>
<td>9</td>
<td>22</td>
<td>$229,925,219</td>
<td>9.7%</td>
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<tr>
<td>Total</td>
<td>66</td>
<td>125</td>
<td>$2,369,590,109</td>
<td></td>
</tr>
</tbody>
</table>

### Applicable* Legacy Projects with ISD after 12/31/2013 by PO

*Applicable Projects refer to projects with a cost estimate greater than $20 Million and a voltage greater than 100 kV

<table>
<thead>
<tr>
<th>Project Owner</th>
<th>Projects</th>
<th>Upgrades</th>
<th>Latest Cost Estimate</th>
<th>% of Total Cost</th>
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<tbody>
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<td>5</td>
<td>$449,040,000</td>
<td>21.5%</td>
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<tr>
<td>ITCGP</td>
<td>1</td>
<td>6</td>
<td>$285,024,557</td>
<td>13.6%</td>
</tr>
<tr>
<td>OGE</td>
<td>3</td>
<td>7</td>
<td>$430,040,000</td>
<td>20.6%</td>
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<tr>
<td>Prairie Wind</td>
<td>1</td>
<td>2</td>
<td>$50,500,000</td>
<td>2.4%</td>
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<tr>
<td>SPS</td>
<td>5</td>
<td>23</td>
<td>$409,082,094</td>
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<tr>
<td>Westar</td>
<td>2</td>
<td>7</td>
<td>$177,367,207</td>
<td>8.5%</td>
</tr>
<tr>
<td>Total</td>
<td>17</td>
<td>61</td>
<td>$2,089,199,858</td>
<td></td>
</tr>
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</table>
Estimated Cost of Legacy Projects Per In-Service Year

Total ($M)

<table>
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<tr>
<th>Year</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>$1,898,539,038</td>
<td>$2,089,199,858</td>
<td>$85,998,768</td>
<td>$55,576,827</td>
<td>$45,645,869</td>
<td>$93,168,787</td>
</tr>
</tbody>
</table>

Legacy Projects with ISD after 12/31/2013 by Cost Breakout

<table>
<thead>
<tr>
<th>Cost Range</th>
<th># of Projects</th>
<th>NTC Cost Estimate</th>
<th>Latest Cost Estimate</th>
<th>% Variance</th>
<th>% of Latest Cost to Total</th>
<th># of Projects Outside +/-20% Bandwidth</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt; $20 Million</td>
<td>17</td>
<td>$1,898,539,038</td>
<td>$2,089,199,858</td>
<td>10.0%</td>
<td>88.2%</td>
<td>8</td>
</tr>
<tr>
<td>Between $15 and $20 Million</td>
<td>5</td>
<td>$78,898,166</td>
<td>$85,998,768</td>
<td>9.0%</td>
<td>3.6%</td>
<td>1</td>
</tr>
<tr>
<td>Between $10 and $15 Million</td>
<td>4</td>
<td>$43,262,500</td>
<td>$55,576,827</td>
<td>28.5%</td>
<td>3.6%</td>
<td>2</td>
</tr>
<tr>
<td>Between $5 and $10 Million</td>
<td>7</td>
<td>$26,588,286</td>
<td>$45,645,869</td>
<td>71.7%</td>
<td>1.9%</td>
<td>6</td>
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<tr>
<td>&lt; $5 Million (or 69 kV)</td>
<td>33</td>
<td>$81,362,026</td>
<td>$93,168,787</td>
<td>14.5%</td>
<td>3.9%</td>
<td>13</td>
</tr>
<tr>
<td>Total</td>
<td>66</td>
<td>$2,128,650,016</td>
<td>$2,369,590,109</td>
<td>11.3%</td>
<td></td>
<td>30</td>
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</tbody>
</table>
MOPC Approved

• Moved all Legacy Projects regardless of voltage or cost estimate with a TO indicated in-service date on or after 1/1/2014 under BP 7060 from BP 7050
• Re-baseline cost estimate totals to current cost estimates, as of 1/31/2014
  – TO provide variance report for differences between the re-baseline estimate compared to the current estimate indicated on the Quarter 4 2013 Project Tracking Report
• If project cost estimate increases 10% or greater over the re-baseline amount provided as of 1/31/2014, a SCERT will be required to be completed for those projects that were moved from BP 7050 to BP 7060
• PCWG will initiate BPR(s) to incorporate recommended changes into pertinent business practices

RARTF
MOPC Reviewed and Approved Report

- Staff presented RARTF to MOPC for review
- MOPC undertook significant discussion of the Report and its potential implementation within the SPP stakeholder groups under the MOPC
  - Initiated an Action Item and modified language in 2015 ITP10 scope to consider Report recommendations
- MOPC approved the Report as being consistent with Tariff requirements

TWG
HPILS Overview

- Model Development Process
- Load Change vs Generation Summary
- Load Summaries by Area
- Other Base Model Assumptions
- Needs Assessments
- Schedule
- Next Steps
- Issues

Model Development Process

**Base Cases**
- 2014ITPNT - 15SPO
- 2012ITP RCAR - 185P0
- 2012ITP RCAR - 235P0

**Loads (Members)**
- Base Load Changes
- Incremental (HPILS) Load Additions

**Generation & Transactions (Members)**
- Retirements and Additions
- Corrections to Existing Generator parameters

**System Topology (Members)**
- Additions for HPILS and generator connections
- Other base case corrections and rating updates
- SPP reduced SPS New Mexico system additions

**NTC and Sharyland (SPP)**
- Removal of Suspended NTC-C’s
- Addition of Approved NTC’s
- Removal of Sharyland transmission ties
Load Change vs Generation Summary

**2015**
- 50/50 Base Load: -24 MW
- 90/10 Base Load: 119 MW
- 50/50 Total Δ: 795 MW
- 90/10 Total Δ: 1549 MW
- *Gen Additions ~110 MW

**2018**
- 50/50 Base Load: 689 MW
- 90/10 Base Load: 856 MW
- 50/50 Total Δ: 1986 MW
- 90/10 Total Δ: 3064 MW
- *Gen Additions ~1719 MW

**2023**
- 50/50 Base Load: 696 MW
- 90/10 Base Load: 801 MW
- 50/50 Total Δ: 2387 MW
- 90/10 Total Δ: 3721 MW
- *Gen Additions ~3441 MW

*Major Generation Additions (> 50 MW, no Wind Farms)

---

2015 Total Load Changes By Area

- 2015 50/50 Load Change from Base Model = 795 MW
- 2015 90/10 Load Change from Base Model = 1549 MW

**2015 Total Load Change by Area**

![Load Change Chart]

- 2015SP0_50-50
- 2015SP0_90-10
2018 Total Load Changes By Area

- 2018 50/50 Load Change from Base Model = 1986 MW
- 2018 90/10 Load Change from Base Model = 3064 MW

2023 Total Load Changes By Area

- 2023 50/50 Load Change from Base Model = 2387 MW
- 2023 90/10 Load Change from Base Model = 3721 MW
Generation Addition Summary

Major Generation Additions* (> 50 MW, no Wind Farms)

- **2015: Total Gen Addition 110 MW**
  - SUNC: 110 MW Rubart Gen

- **2018: Total Gen Addition 1,719 MW**
  - NPPD: New Gas Turbine Addition 160 MW at Moore 345 kV
  - SPS: Antelope_CT Gen 778 MW (Connected to Tuco_INT 345 kV) – to cover GSEC load, currently 189 MW
  - SPS: Orla Gen 560 MW (Connected to Road Runner 345 kV initially)
  - WFEC: 300 MW Mooreland4 (Connected to Woodward 345 kV)

- **2023: Total Gen Addition 3,441 MW**
  - OKGE: 562 MW Seminole (Connected to Seminole 345 kV)
  - SPS: 300 MW PX_Gen (Connected to Plant X 230 kV)
  - OPPD: 160 MW Cass Gen (only in 90/10 model, Connected to S3740)
  - LPL: 700 MW Future Gen (Connected to Holly 230 kV)

*Nameplate capacity amounts, not necessarily Pgen dispatched

**Cumulative from 2015

Other Base Model Highlights

Consistent with the approved scope, its important to note that resource assumptions for HPILS were the provided by LSEs, and assumptions were made by staff to fill gaps, e.g., LP&L

Select retirements at Moore Co, Plant X and Cunningham assumed by SPS

Transactions sourced from Oneta were assumed to support majority of WFEC supply needs to serve NM Coops and those amounts grew to 300MW in 2023
Base Configuration Summary

- Scope specified HPILS would be based on “existing system plus approved NTCs”. That task was finalized August 20th.
- Scope included the removal of the following Suspended NTC-C’s which would be reevaluated:
  - Tuco to New Deal 345 kV Line
  - Tuco to Amoco to Hobbs 345 kV Line
  - Grassland to Wolfforth 230 kV Line
- Disconnection of the Sharyland Transmission
  - Cirrus Wind to Borden Co 230 kV Line (345kV design)
  - Line Section near NEF (future sub) to Midland Co 230 kV Line (345kV design)
  - 138 kV between Midland Co and Borden Co

SPS Configuration Changes

- SPS New Mexico Area Development
  - 115 kV Transmission Line Additions (137 miles)
    - 115 kV line from New Sub #3 Tap to serve New Sub #3 Load.
    - 115 kV line from New Sub #5 to Dollarhide.
    - 115 kV line from existing NEF to Andrews (New NEF).
    - 115 kV line from Hopi Sub to North Living to China Draw.
    - 115 kV line from North Living to New Sub #1 and New Sub #2 to Andrews (new NEF)
    - 115 kV line from Road Runner to Battle Axe
    - Upgrade China Draw from 69 to 115 kV and add new 115 kV line from China Draw to Wood Draw.
  - 2018 Transmission Additions
    - 345 kV line operated at 230 kV Line from Potash Junction to Road Runner to Orla Generation (85 miles) [Note Potash Junction – Road Runner has 12/15 ISD]
    - 2 x 250 MVA 230/115 kV Transformers at Road Runner
    - China Draw SVC @ 100 MVAR
  - 2023 Transmission Additions
    - Upgrade 345 kV line from Potash Junction to Road Runner to Orla Generation
    - 1 x 448 MVA 345/115 kV Transformers at Road Runner
    - Increase China Draw SVC to 200 MVAR from 100 MVAR
    - New SVC @ 200 MVAR connected to Road Runner 115 kV
Final Model Changes Prior to Contingency Runs

Line Ratings “Discrepancies” (ITPNT cases vs HPILS cases)
1. ITP10 Base Cases Compared to HPILS Study Models*
   - 2015 ITPNT Compared to 2015 50/50 & 90/10 Models
   - 2019 ITPNT Compared to 2018 50/50 & 90/10 Models
   - 2024 ITPNT Compared to 2023 50/50 & 90/10 Models

2. Rate A and Rate B Differences
   - Total of 126 Rate A, 169 Rate B Differences in the 2015 Models
   - Total of 123 Rate A, 166 Rate B Rating Differences in the 2018 Models
   - Total of 65 Rate A, 68 Rate B Rating Differences in the 2023 Models

3. Lower Rate A and Rate B Ratings Replaced in the HPILS R7 Models

*ITPNT Models available on Sep 3, 2013.

Need Assessments

- **Methodology**
  - **Study Area**: SPP and External Areas (1st Tier Neighbors)
  - Monitor 69 kV and Above Facilities Within Study Area
  - Outage 100kV+ facilities for N-1
- **Posted N-0 and N-1 results Sept 15th**
- **Responses/Solutions due Sept 20th and 24th**
- **Discussed next steps at 9/25 Meeting at OCC**
  - Priority to identify reliability projects to address 50/50 projections, as well as incremental needs for 90/10 cases
**HPILS Process Chart**

Legend:
- Task 1: Data Collection
- Task 2: Reliability Model Dev.
- Task 3: Economic Model Dev.
- Task 4: Reliability Needs Identification
- Task 5: Reliability Projects Development
- Task 6: Economic Needs Identification
- Task 7: Economic Projects Development
- Task 8: B/C Metrics Calculations
- Task 9: Final Reliability Analysis
- Task 10: Study Report

**Schedule for Reliability Project Development**

<table>
<thead>
<tr>
<th>Task</th>
<th>Description</th>
<th>Who</th>
<th>Start Date</th>
<th>Target Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Task 5</td>
<td>Develop Reliability Projects</td>
<td>SPP/BCM&amp;D</td>
<td>13-Sep-13</td>
<td>26-Sep-13</td>
</tr>
<tr>
<td></td>
<td>Develop 2023 Reliability Projects</td>
<td>SPP/BCM&amp;D</td>
<td>13-Sep-13</td>
<td>26-Sep-13</td>
</tr>
<tr>
<td></td>
<td>Review 2023 Develop Reliability Projects</td>
<td>Members</td>
<td>26-Sep-13</td>
<td>2-Oct-13</td>
</tr>
<tr>
<td></td>
<td>Review 2018 Develop Reliability Projects</td>
<td>Members</td>
<td>26-Sep-13</td>
<td>2-Oct-13</td>
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<tr>
<td></td>
<td>Review 2015 Develop Reliability Projects</td>
<td>Members</td>
<td>26-Sep-13</td>
<td>2-Oct-13</td>
</tr>
<tr>
<td></td>
<td>Revise and Finalize 2015 Reliability Projects/Fixes</td>
<td>SPP/BCM&amp;D</td>
<td>26-Sep-13</td>
<td>3-Oct-13</td>
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## Ongoing and Future HPILS Tasks

<table>
<thead>
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<th>Task</th>
<th>Description</th>
<th>Duration</th>
</tr>
</thead>
<tbody>
<tr>
<td>3B</td>
<td>Economic Model Review</td>
<td>Oct</td>
</tr>
<tr>
<td>6</td>
<td>Economic Needs Identification</td>
<td>Oct – Nov</td>
</tr>
<tr>
<td>7</td>
<td>Develop Economic Projects</td>
<td>Nov - Dec</td>
</tr>
<tr>
<td>8</td>
<td>Portfolio Assessment &amp; Metrics</td>
<td>Dec – Jan 2014</td>
</tr>
<tr>
<td>9</td>
<td>Final Reliability Assessment</td>
<td>Jan – Feb 2014</td>
</tr>
<tr>
<td>10</td>
<td>Draft Report</td>
<td>Mar 2014</td>
</tr>
</tbody>
</table>

## Next Steps

- Working to finalize reliability upgrades for 2023 50/50 and then needs for 2018 and 2015, with identification of incremental projects to address 90/10 needs
- Develop expansion plans that are needed and practical over time, and any mitigation plans which may be necessary
- Finalize economic models
- Next HPILS TF Meeting 10/17 or 23
- Present preliminary reliability results and recommendations to TWG in mid-November and potentially share at Planning Summit
2014 ITPNT UPDATE

2014 ITPNT Inputs

• 2 Scenario models for each season
  – Light Load: 2014 and 2019
  – Also created CBA scenario for each season

• Analyzes System Intact and N-1 conditions
  – 69 kV and above in SPP
  – 100 kV and above in 1st tier areas

• Monitors for potential thermal and voltage violations
  – 69 kV and above in SPP
  – 100 kV and above for 1st tier areas
Draft 2014 ITPNT Portfolio

2014 ITPNT Draft Portfolio Cost $686M*

*Incorporates SPP Conceptual Estimates for $393M

Draft Project Plan Breakdown

Approx. 213 Total Miles of New Line

- 41 mi
- 40 mi
- 28 mi
- 20 mi
- 161 kV
- 138 kV
- 115 kV
- 69 kV
Draft Project Plan Breakdown

Approx. 173 Total Miles of Rebuild/Reconductor*

*Does not include 70 miles of voltage conversion

Modified & Withdrawn NTCs

- **Modified NTCs**
  - 11 Accelerations
  - $211M of previously approved upgrades

- **Withdrawn NTCs**
  - 11 upgrades withdrawn
  - $66M approved
Completed work
- Scope
- Model
- Reliability Assessment
- Violations
- Solution Development
- CBA Model Creation
- Requested SCERTs

Next Steps
- Stability Assessment
- CBA Solution Development
- NTC Re-evaluations
- Final Portfolio Development

TODAY’S MOPC

November 20 - Planning Summit
November 22 - SCERT Submittal Deadline
December 18 - TWG Review
January 2014 - Final Report/Portfolio NTCs Issued
February 2014 - NTCs Issued
CBA Analysis

- 5 CBA Scenario models compared to 1 in 2013 ITPNT
- TWG approved system constraints beyond the SPP portion of the NERC Book of Flowgates
- TWG will review any CBA needs and recommend to MOPC if a solution is needed.

RTWG
Integrated Marketplace Compliance Filing

- Received Compliance Order from FERC on September 20, 2013, SPP filing in response is due November 19, 2013
- RTWG has developed numerous TRRs in response to the Sept 20 Order
- MOPC and BOD/MC meetings are scheduled for November 4, 2013 to review and approve these compliance TRRs
- Most TRRs are expected to be on the consent agenda, and less than ten TRRs are anticipated to need discussion by the MOPC and/or BOD/MC
Integrated Marketplace System Update

Board of Directors

October 2013
Bruce Rew, PE

Integrated Marketplace Topics

• TCR Market Trials
• Market Trials
• Parallel Operations and Deployment Testing
• Cutover and Go-Live Planning
• Readiness and Outreach
• Post Go-Live Activities
TCR Market Trials & Go-Live

• TCR Market Trials - Complete
  – Successfully completed Phase 2 of TCR Market Trials on 9/27

• TCR Go/No-Go Process – In Progress
  – Published TCR Go/No-Go Data on 10/3
  – CWG voted 13 to 12 to Go-Live with 5 additional support votes
  – SPP Staff Recommended proceeding with Go-Live
  – TCR Recommendation report posted on SPP website
  – On October 11 Go-Live Team Unanimously approved TCR Go-Live

• TCR Go-Live on October 18
  – TCR System will go live in accordance with SPP Integrated Marketplace Protocols

Structured/Unstructured Market Trials

• Structured/Unstructured Market Trials Accomplishments
  – Currently Performing Operating Days Monday – Friday
  – Currently have tested or in the process of testing all scoped SMT functionality
  – Completed 62 Official Operating Days to date (as of 10-17)
  – Successfully completed 25 entire Scenarios and 2 partial Scenarios of 49 Structured Scenarios (as of 10-14)
  – Completed 52 Unstructured days to date (as of 10-17)

• Upcoming SMT Efforts
  – Official Operating Days will increase to Monday – Sunday starting 10-20
  – Completing testing Markets Software version 1.7
  – Operating Days will continue through November 3
    – Some Structured Scenarios will be tested during Parallel Operations beginning 11-12
  – Structured/Unstructured Market Trials Concludes on 11-3
Scenario Tracker as of Oct 16

• Summary - Successful:
  – 25 Scenarios Successful
  – 2 partial Scenarios (21: sub-scenarios #1, 3-8 and 15 part 1)
  Successful

• Summary - Retests:
  – 1 entire Scenario (33) all MPs will retest during Structured Market Trials
  – 1 entire Scenario (11) and 1 partial Scenario (15 part 2) all applicable MPs will retest during Parallel Ops
  – 22 individual retest requests pending
  – 5 entire Scenarios and 1 partial Scenario retesting is not high priority or required to be performed in Market Trials Production environment

### Scenario Tracker as of Oct 14

<table>
<thead>
<tr>
<th>Scenario ID</th>
<th>Scenario Title</th>
<th>SPP Successful</th>
<th>SPP Unsuccessful</th>
<th>MP Status</th>
<th>Comments</th>
<th>MP Fail Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Delay Market</td>
<td>X</td>
<td></td>
<td>Fail</td>
<td>1 MP requested retest</td>
<td>MP Adjustments denied</td>
</tr>
<tr>
<td>2</td>
<td>Failure to Publish OR</td>
<td>X</td>
<td></td>
<td>Fail</td>
<td>4 MPs retesting 10/14</td>
<td>MP Systems were not ready</td>
</tr>
<tr>
<td>4</td>
<td>Outage Simulation</td>
<td>X</td>
<td></td>
<td>Fail</td>
<td>4 &quot;retests&quot; w/ 28b</td>
<td>MPs want to verify ICCP</td>
</tr>
<tr>
<td>5.1</td>
<td>DA Capacity Shortage</td>
<td></td>
<td>X</td>
<td>Pending Reschedule</td>
<td>Reschedule pending R1.8</td>
<td></td>
</tr>
<tr>
<td>5.2</td>
<td>RUC Capacity Shortage</td>
<td></td>
<td>X</td>
<td>Fail</td>
<td>3 MPs requested retest</td>
<td>ICCP not working for MPs; want to verify messages</td>
</tr>
<tr>
<td>6.1</td>
<td>DA Capacity Excess</td>
<td></td>
<td>X</td>
<td>Pending Reschedule</td>
<td>Reschedule pending R1.8</td>
<td></td>
</tr>
<tr>
<td>6.2</td>
<td>RUC Capacity Excess</td>
<td></td>
<td>X</td>
<td>Pending Reschedule</td>
<td>Reschedule pending R1.8</td>
<td></td>
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<tr>
<td>8</td>
<td>DA Scarcity Pricing</td>
<td></td>
<td>X</td>
<td>Fail</td>
<td>Insufficient MP Response</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>EDR Deployment</td>
<td></td>
<td>X</td>
<td>Pending Reschedule</td>
<td>Reschedule pending R1.8</td>
<td></td>
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<tr>
<td>12</td>
<td>OOME</td>
<td></td>
<td>X</td>
<td>Fail</td>
<td>2 MPs requested retest</td>
<td>MPs did not have ICCP</td>
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<tr>
<td>13</td>
<td>Demand Response</td>
<td></td>
<td>X</td>
<td>Pass</td>
<td></td>
<td></td>
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<tr>
<td>14.1</td>
<td>Low Load High Wind</td>
<td></td>
<td>X</td>
<td>Pass</td>
<td></td>
<td></td>
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<tr>
<td>14.2</td>
<td>Low Load High Wind</td>
<td></td>
<td>X</td>
<td>Pass</td>
<td></td>
<td></td>
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<tr>
<td>15</td>
<td>Commitment Mismatch p1</td>
<td></td>
<td>X</td>
<td>Fail</td>
<td>1 MP confirming issues resolved</td>
<td></td>
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<tr>
<td>15.1</td>
<td>Commitment Mismatch p2</td>
<td></td>
<td>X</td>
<td>Pending Reschedule</td>
<td>Reschedule pending R1.8</td>
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<tr>
<td>16.1</td>
<td>DA Mitigation</td>
<td></td>
<td>X</td>
<td>Pending Reschedule</td>
<td>Reschedule pending R1.8</td>
<td></td>
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<tr>
<td>16.2</td>
<td>RUC Mitigation</td>
<td></td>
<td>X</td>
<td>Insufficient MP Response</td>
<td></td>
<td></td>
</tr>
<tr>
<td>16.3</td>
<td>RTBM Mitigation</td>
<td></td>
<td>X</td>
<td>Pending Reschedule</td>
<td>Reschedule pending R1.8</td>
<td></td>
</tr>
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</table>

Scenario tracker process measures if the MPs consider a scenario successful
Scenario Tracker as of Oct 14

### Scenario Tracker Process

<table>
<thead>
<tr>
<th>Scenario ID</th>
<th>Scenario Title</th>
<th>SPP Successful</th>
<th>SPP Unsuccessful</th>
<th>MP Status</th>
<th>Comments</th>
<th>MP Fail Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>17.3</td>
<td>Reserve Cap Testing</td>
<td>X</td>
<td></td>
<td>Fail</td>
<td></td>
<td>1 MP requested retest; retest pending R1.8</td>
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<tr>
<td>18</td>
<td>Failure Modes</td>
<td>X</td>
<td></td>
<td>Pass</td>
<td></td>
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<td>19</td>
<td>Emergency Logic</td>
<td>X</td>
<td></td>
<td>Insufficient MP Response</td>
<td></td>
<td></td>
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<tr>
<td>20</td>
<td>CRD Event</td>
<td>X</td>
<td></td>
<td>Fail</td>
<td></td>
<td>1 MP requested retest</td>
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<tr>
<td>21</td>
<td>RTBM Scarcity #1, 3-8</td>
<td>X</td>
<td></td>
<td>Insufficient MP Response</td>
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<td></td>
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<tr>
<td>22</td>
<td>RTBM Scarcity #2</td>
<td>X</td>
<td></td>
<td>Fail</td>
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<td>1 MP requested retest</td>
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<tr>
<td>23</td>
<td>Manual RUC</td>
<td>X</td>
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<td>Pass</td>
<td></td>
<td></td>
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<tr>
<td>24</td>
<td>Spring Load Profile</td>
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<td>25.1</td>
<td>Fall Load Profile</td>
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<td>25.2</td>
<td>Winter Load Profile</td>
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<td>Pass</td>
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<td>26.1</td>
<td>Winter Load Profile</td>
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<td>Pass</td>
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<td></td>
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<td>26.2</td>
<td>Winter Load Profile</td>
<td>X</td>
<td></td>
<td>Pass</td>
<td></td>
<td></td>
</tr>
<tr>
<td>27.1</td>
<td>Block Demand Response</td>
<td>X</td>
<td></td>
<td>Pass</td>
<td></td>
<td></td>
</tr>
<tr>
<td>27.2</td>
<td>Block Demand Response</td>
<td>X</td>
<td></td>
<td>Pass</td>
<td></td>
<td></td>
</tr>
<tr>
<td>28</td>
<td>Ramp Reservations</td>
<td>X</td>
<td></td>
<td>Pass</td>
<td></td>
<td></td>
</tr>
<tr>
<td>29</td>
<td>Loss of ICCP</td>
<td>X</td>
<td></td>
<td>Pass</td>
<td></td>
<td></td>
</tr>
<tr>
<td>30</td>
<td>Day before DA RUC</td>
<td>X</td>
<td></td>
<td>Pass</td>
<td></td>
<td></td>
</tr>
<tr>
<td>31</td>
<td>Off Supp Deployment</td>
<td>X</td>
<td></td>
<td>Pass</td>
<td></td>
<td></td>
</tr>
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<td>32</td>
<td>Off Supp Deployment</td>
<td>X</td>
<td></td>
<td>Pass</td>
<td></td>
<td></td>
</tr>
<tr>
<td>33</td>
<td>Off Supp Deployment</td>
<td>X</td>
<td></td>
<td>Pass</td>
<td></td>
<td></td>
</tr>
<tr>
<td>34</td>
<td>Off Supp Deployment</td>
<td>X</td>
<td></td>
<td>Fail</td>
<td></td>
<td>6 MPs requested retest</td>
</tr>
</tbody>
</table>

Scenario tracker process measures if the MPs consider a scenario successful.
Parallel Operations

Parallel Operations Preparation Accomplishments

- Parallel Operations MP Kick-off on 10/8
- Published the 3 Month Parallel Operations Calendar.
- Published v3.0 of the Parallel Operations Market Participant Guide.
- Published the Parallel Operations Communications Plan

Upcoming Parallel Operations Efforts

- Parallel Operations Go/No-Go Process
  - Publish Parallel Ops Go/No-Go Data on 10/28 to CWG
  - Go/No-Go data is based on the published Go/No-Go Criteria
  - Recommendation Report is published to Go-Live Team (and CWG) on 11/1, Decision on 11/6
  - Assuming a positive Go/No-Go, Parallel Operations will start on 11/12 and continue through 1/31
  - This will include some iterations of Structured Tests as a carry-over from SMT

Parallel Operations Go/No-Go Criteria

There are 24 Parallel Operations Criteria.

- 3 are complete
- 13 are tracking on time
- 7 are at tracking at risk
- 1 has not started tracking yet

The following criteria are at risk:

- PO-03: 100% of Structured/Unstructured testing scenarios are successfully executed and completed or removed from scope and successful completion is validated through Readiness Metric TRL-02.
- PO-04: SPP and member ICCP Models are up to date and all ICCP and XML inbound and outbound Marketplace data points have been validated with all applicable Market Participants as part of Structured Market Trials
Parallel Operations Go/No-Go Criteria

- The following criteria are at risk (cont.):
  - PO-10: FIT (Functional Integration Testing) Stage Exit Criteria is met by all applicable workstreams and Business Owner approval is obtained (with the exception of Settlements).
  - PO-13: Performance Testing Exit Criteria is met by all applicable workstreams and Business Owner approval is obtained
  - PO-14: Non Functional Testing should be completed and reviewed by SPP Technical Architects validating the systems demonstrate sufficient stability to commence Parallel Operations
  - PO-16: MCE Certification sign-off obtained from Markets Business Owners
  - PO-19: Protocol Compliance has been validated

Integrated Deployment Testing

- Integrated Deployment Testing Preparation Accomplishments
  - Updated and posted v2.0 of the Integrated Deployment Test Market Participant Guide.
  - Integrated Deployment Testing Roll-in/Roll-out Plans (TRL.079)
    - Published the SPP IDT Roll-In/Roll-Out plan for distribution to the EIS BAs on 09-16
    - Received all 16 BA initial plans for the Integrated Deployment Test Roll-In/Roll-Out.
    - Completed BA Readiness Calls on 10/4
  - Operating Protocols published to CBASC on 9/3
  - EIS BAs have internally reviewed and provide finalized Roll-in/Roll-out Plans.

- Upcoming Parallel Operations Efforts
  - Perform Mock Deployment Test on 11/14
  - Begin Official Integrated Deployment Tests on 11/19
  - Complete Integrated Deployment Tests on 1/30
MARKET TRIALS PHASE CUTOVER &
GO-LIVE PLANNING

Market Trials Phase Cutover & Go-Live Planning

- **TCR Go-Live – October 2013**
  - Go/No-Go Process -- **Approved**
  - Internal TCR Go-Live Deployment Plan -- **Approved**

- **Parallel Operations/IDT Go-Live – November 2013**
  - Go/No-Go Process – **To Start 10/28**
  - Internal Parallel Operations & IDT Go-Live Deployment Plan – **In Progress**
    - A tactical plan of functional and technical activities to allow SPP to successfully cut-over to Parallel Operations and Integrated Deployment Testing.
Market Trials Phase Cutover & Go-Live Planning

• Markets Go Live – March 2014
  – People
    ▪ **SPP Staff Readiness**: 12/20/13 - High impact business area’s resources are performing Go-Live functions.
    ▪ **MP Readiness**: 12/20/13 - MPs have submitted MP Readiness Self-Certification
  – Processes
    ▪ **Marketplace Process & Procedure Readiness completed by 1/31/14**
  – Systems
    ▪ **System Readiness**: All by 12/20/13
      – Systems are protocol-compliant
      – Systems have zero critical defects
      – 12/20/13 - SPP CBA will balance the region’s supply and demand, maintain frequency, and maintain electricity flows between adjacent BAs, meeting all applicable NERC standards and criteria.

Market Trials Phase Cutover & Go-Live Planning

• Markets Go Live – March 2014 (Continued)
  – Governance
    ▪ **FERC Approval**: 12/27/2013 - Submit Readiness Go-Live Filing
    ▪ **NERC/SERC Certification & BA Certification**: 1/15/2014 - NERC certifies SPP as the CBA
    ▪ **Audit Compliant**: 3/1/2014 - The Integrated Marketplace solution will meet all Business & SSAE Control Objectives
External Readiness

- Completed Readiness Metrics gap analysis
  - 10 new metrics, 6 edited metrics
  - Updated Readiness Metrics will be filed with FERC
- Developed Parallel Ops Go/No-Go Criteria
  - Reviewed with CWG and Readiness Liaisons
- Continued outreach for MP readiness
MPs Removed from Model

Due to lack of participation and responsiveness, the following six MPs were removed from the model to prevent unintended risks during upcoming phases of Market Trials:

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Week Removed</th>
</tr>
</thead>
<tbody>
<tr>
<td>INFINITY WIND HOLDINGS, LLC</td>
<td>9/23/2013</td>
</tr>
<tr>
<td>J ARON &amp; COMPANY</td>
<td>9/23/2013</td>
</tr>
<tr>
<td>SARACEN ENERGY WEST</td>
<td>9/23/2013</td>
</tr>
<tr>
<td>TRADEMARK MERCHANT ENERGY, LLC (Former Kansas Energy, LLC)</td>
<td>9/23/2013</td>
</tr>
<tr>
<td>TWIN EAGLE RESOURCE MANAGEMENT, LLC</td>
<td>9/23/2013</td>
</tr>
<tr>
<td>UNION ELECTRIC COMPANY DBA AMEREN MISSOURI</td>
<td>9/23/2013</td>
</tr>
</tbody>
</table>

*Made effective for the 10/1 Model

Readiness Metrics Status

As of October 4, there are 50 Readiness Metrics (21 Operations, 1 RSG, 3 Market Trials, 1 CBA, 3 Connectivity, 4 Internal, 2 Registration, 3 Regulatory, 6 TCR, 6 Settlements)

- 5 are complete (blue status)
- 26 are tracking on time (green status)
- 8 are at tracking risk (yellow status)
- 3 are tracking behind
- 8 have not started tracking (grey status)
MP & Vendor Readiness

• SPP performed outreach to vendors and MPs to understand concerns and needs and offer assistance
• MPs completed system readiness survey and provided responses on 9/27
• Readiness Forum to discuss vendor and MP readiness - Wednesday, October 9th
• MP Identified Risks:
  – Test Scenario Delays/Changes
  – Vendor System Readiness
  – SPP System Readiness
  – API Testing/Delays and Changes
  – Data Validation Inadequate
  – Bid to Bill Functionality

Upcoming Member Milestones

<table>
<thead>
<tr>
<th>Member Milestone</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market Trials Parallel Operations - EIS BAs provide Operating Protocol data to SPP</td>
<td>10/1/13</td>
</tr>
<tr>
<td>TCR Go No-Go CWG Recommendation Complete</td>
<td>10/7/13</td>
</tr>
<tr>
<td>TCR_Verify historical peak load</td>
<td>10/17/13</td>
</tr>
<tr>
<td>TCR Go-Live</td>
<td>10/18/13</td>
</tr>
<tr>
<td>Parallel Operations Go No-Go CWG Recommendation Complete</td>
<td>10/31/13</td>
</tr>
<tr>
<td>Reserve Sharing Group Agreements Executed</td>
<td>11/1/13</td>
</tr>
<tr>
<td>Structured/Unstructured Testing Ends</td>
<td>11/4/13</td>
</tr>
<tr>
<td>Integrated Deployment Testing Start (Go/No-Go Checkpoint)</td>
<td>11/6/13</td>
</tr>
<tr>
<td>CPL SERC at SPP for Certification</td>
<td>11/11/13</td>
</tr>
<tr>
<td>Conduct Market Trials Parallel Operations Test_Begin</td>
<td>11/12/13</td>
</tr>
<tr>
<td>Return MP Readiness Self-Certification</td>
<td>12/20/13</td>
</tr>
<tr>
<td>Marketplace Go Live</td>
<td>3/1/14</td>
</tr>
</tbody>
</table>
Filing for GFA – Required filing as a result of FERC’s September 30, 2013 Order Conditionally Accepting SPP’s Proposed Tariff Revisions Relating to GFA Carve Outs

October 30th

Final Supplemental Filing for Go-Live – Filing to include Tariff Revisions for Go-Live (March 1, 2014)

Early November

Soon After October 29th

MC/BOD meeting

Compliance Filing – Required filing as a result of FERC’s September 20, 2013 Order Conditionally Accepting in Part and Rejecting in Part SPP’s Proposed Tariff Revisions

November 19, 2013

Readiness Certification Filing – Filing to inform FERC of SPP readiness

December 27, 2013

Integrated Marketplace- 1-Year Post Go-Live

• Go-Live Support Activities
  – Go-Live Day-to-Day Operations Support
  – Go-Live System Support
  – Go-Live System Emergency & Maintenance Patches

• Post Go-Live Projects
  – Regulation Compensation *(FERC-Mandated)*
  – Market-to-Market *(FERC-Mandated)*
  – Long Term Congestion Rights (LTCRs) *(FERC-Mandated)*
  – Pseudo-Tie Out *(Resettlement Implications)*
  – IT Environments Buildout for Marketplace *(Necessary)*
  – Enhanced Combined Cycle- Member Requested*
  – Go-Live “Required” System Enhancements

*Desired implementation date is one-year post go-live
Southwest Power Pool  
Regional State Committee, Board of Directors/Members Committee &  
Regional Entity Trustees  
Future Meeting Dates & Locations

<table>
<thead>
<tr>
<th>Year</th>
<th>Event</th>
<th>Date</th>
<th>Location</th>
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<tbody>
<tr>
<td>2013</td>
<td>BOD</td>
<td>November 4</td>
<td>Teleconference</td>
</tr>
<tr>
<td></td>
<td>** BOD</td>
<td>December 10</td>
<td>Little Rock</td>
</tr>
<tr>
<td>2014</td>
<td>RET/RSC/BOD</td>
<td>January 27-28</td>
<td>Austin</td>
</tr>
<tr>
<td></td>
<td>RET/RSC/BOD</td>
<td>April 28-29</td>
<td>Oklahoma City</td>
</tr>
<tr>
<td></td>
<td>*BOD</td>
<td>June 9-10</td>
<td>Little Rock</td>
</tr>
<tr>
<td></td>
<td>RET/RSC/BOD</td>
<td>July 28-29</td>
<td>Omaha</td>
</tr>
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<td></td>
<td>RET/RSC/BOD</td>
<td>October 27-28</td>
<td>Little Rock</td>
</tr>
<tr>
<td></td>
<td>** BOD</td>
<td>December 9</td>
<td>Little Rock</td>
</tr>
<tr>
<td>2015</td>
<td>RET/RSC/BOD</td>
<td>January 26-27</td>
<td>Dallas</td>
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<td></td>
<td>RET/RSC/BOD</td>
<td>April 27-28</td>
<td>Tulsa</td>
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<td>*BOD</td>
<td>June 8-9</td>
<td>Little Rock</td>
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<td></td>
<td>RET/RSC/BOD</td>
<td>July 27-28</td>
<td>Kansas City</td>
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<td></td>
<td>RET/RSC/BOD</td>
<td>October 26-27</td>
<td>Little Rock</td>
</tr>
<tr>
<td></td>
<td>**BOD</td>
<td>December 8</td>
<td>Little Rock</td>
</tr>
</tbody>
</table>

The RET/RSC/BOD meetings are Mon/Tues with the RET meeting on Monday morning, the RSC meeting on Monday afternoon, the BOD/Members Committee meeting on Tuesday.

* The June BOD meeting is for educational purposes. There will be no RSC of RET meetings in conjunction with this meeting.

** The December BOD meeting is intended to be a one day in and out meeting for administrative purposes. There will be no RSC or RET meetings in conjunction with this meeting.
Agenda Item 1 – Administrative Items
SPP Board of Directors Chair, Mr. Jim Eckelberger, called the meeting to order at 8:05 a.m. Mr. Eckelberger asked for a round of introductions. There were 123 people in attendance either in person or via phone representing 34 members (Attendance List – Attachment 1). Mr. Nick Brown reported proxies (Proxies – Attachment 2).

Mr. Eckelberger referred to the Special Meeting of Members minutes from January 29, 2013 (Minutes 1/29/13 – Attachment 3). Mr. Phil Crissup moved to approve the minutes as presented; Mr. Brett Kruse seconded. The Membership voted in unanimous approval.

Agenda Item 2 – Corporate Governance Committee Report
Mr. Nick Brown presented the Corporate Governance Committee report (CGC Report – Attachment 4). Mr. Brown stated that the Committee is responsible for nominating candidates to the Membership for three-year terms for the Board of Directors, Members Committee, and the Regional Entity Trustees. Nominations for the Members Committee were also entertained from the floor. Hearing none, the Membership was asked to vote for the following nominees to fill the positions with terms commencing January 1, 2014:

Board of Directors:
Phyllis Bernard
Julian Brix

Members Committee (sector):
Kelly Harrison (IOU)
Stuart Solomon (IOU)
Noman Williams (Cooperatives)
Jeff Knottek (Municipals)
Rob Janssen (IPP/Marketers)

Regional Entity Trustees:
John Meyer

In addition, Dave Osburn (OMPA) was nominated to fill a current vacancy for the Municipals sector representative. His term will start immediately and expire at the end of 2014. All nominees were elected.

Agenda Item 3 – President’s Report
Mr. Nick Brown provided the President’s Report (President’s Report – Attachment 5). Mr. Brown stated this year the focus was on culture drivers of Continuous Improvement, Efficiency and Collaboration. He addressed several topics:

Administrative:
- Staffing is nearing completion with half the additions this year (50) versus the previous year. There are only two versus 20 positions now forecast for next year, indicating a maturing staff.
- The Administrative Fee of $0.38 will be recommended to cover costs of the Integrated Marketplace. SPP remains very well positioned in comparison to peers and will continue to search for efficiencies.
- Staff, despite pressures of maintaining the status quo with the Integrated Marketplace development and testing, received a clean NERC 693 Audit.
- Arkansas Business and the Arkansas Economic Development Commission named SPP as one of the 12 Best Places to Work in Arkansas with an overall engagement score of 94 versus a national average of 68.
• SPP earned the LEEDS Gold certification, American Society of Interior Designers Gold Award and Ovation Award as Commercial Project of the year for Arkansas, Louisiana and Mississippi for the new campus.

Membership: SPP continues to work with Basin, Heartland and WAPA. Public statements have been positive and SPP is awaiting a WAPA notice of intent in the Federal Register.

Operations:
• SPP’s 2013 completed transmission was: NTC 254.4 new miles and 314 rebuild/reconductor at $606,513,706; non-NTC 6.3 new miles and 17.4 rebuild/reconductor at $69, 499,186
• Mr. Lanny Nickell reported Generation Interconnection and Aggregate Study (GI/AG) improvements.
• Wind reached an all-time market peak of 6467 MW on October 10 at 1731, representing 28.4% of load.
• SPP started an effort to indentify frequency and voltage control.
• Gas/Electric coordination efforts are underway and SPP has met with over 85% of suppliers.

Order 1000 Compliance: Mr. Brown thanked everyone for their diligent efforts regarding compliance. The removal of Right of First Refusal (ROFR) remains problematic and it will take many years to fully appreciate the impact of this order. The Markets and Operations Policy Committee (MOPC) and the Board of Directors have each scheduled teleconferences on November 4 to finalize compliance issues for filing on November 18.

MISO Seams Negotiations: SPP and the Midcontinent ISO have signed a Memorandum of Understanding (MOU) on October 21, 2013 containing provisions to resolve the seams dispute. Efforts are also underway with PJM to provide consistency. Oral arguments in the US District Court regarding 5.2 of the JOA went very well.

Interregional: Work continues at NERC to improve the focus on improving ambiguous standards rather than rigorous enforcement.

Integrated Marketplace:
• Progress is tracked three ways; project team schedule, internal audit, and outside consultant.
• Internal Audit’s assessment of eight sub-areas is: one green, one yellow, five orange (medium – high risk), and one red (high risk of endangering program goals). Mr. Brown encouraged market participants to increase their level of readiness.

The organization engagement of SPP in 2013 has involved many areas:
• Regional State Committee and Cost Allocation Working Group
• Regional Cost Allocation Review initiative
• GI/AG Study initiative
• Order 1000
• Seams efforts
• Board’s engagement with Members
• Corporate Governance Committee work on withdrawal obligations

Mr. Brown opened the floor for any questions regarding the Metrics. Following some discussion, he stated that the December Board meeting will focus on SPP’s Metrics and Organizational Effectiveness.

Adjournment
With no further business, Mr. Eckelberger adjourned the Annual Meeting of Members at 8:45 a.m.

Stacy Duckett, Corporate Secretary
Southwest Power Pool

BOARD OF DIRECTORS/MEMBERS COMMITTEE MEETING
AND ANNUAL MEETING OF MEMBERS
October 29, 2013
SPP Offices, Little Rock, AR

• AGENDA •
8:00 a.m. – 3:00 p.m. CDT

Annual Meeting of Members
1. Call to Order and Administrative Items................................................................. Mr. Jim Eckelberger
2. Elections of Directors, Members Committee Representatives, and RE Trustee ........ Mr. Nick Brown
3. President’s Report ........................................................................................................ Mr. Nick Brown

Adjourn for Board of Directors/Members Committee Meeting

Board of Directors/Members Committee Meeting
1. Call to Order and Administrative Items................................................................. Mr. Jim Eckelberger
2. Board Reports
   a. Regional State Committee Report................................................................. Commissioner Tom Wright
   b. Federal Energy Regulatory Commission Report........................................ Mr. Patrick Clarey
   c. Regional Entity Trustees Report................................................................. Mr. John Meyer
   d. Oversight Committee Report....................................................................... Mr. Josh Martin
3. Consent Agenda ....................................................................................................... Mr. Jim Eckelberger
   a. Approve July 30, 2013 minutes
   b. Markets and Operations Policy Committee Recommendations
      i. ORWG: CRR 005, 006, and 007
      ii. MWG: MPRR 069, 101, 131, 132, 135, 138, 139, 140, 141, 149
      iii. SPCWG: Criteria 7.0
      v. Staff: Novation from GMO & KCPL to Transource
         1. Iatan-Nashoa
         2. NE City to Sibley
      vi. PCWG: Bowers - Howard
   c. Human Resources Committee Recommendation
      i. Pension Plan
4. Corporate Governance Committee Report.............................................................. Mr. Nick Brown
5. Finance Committee Report...................................................................................... Mr. Harry Skilton
6. Markets and Operations Policy Committee Report .......................................................Mr. Rob Janssen
   a. RTWG: TRR 104, 110
   b. MWG: MPRR 130, 145
   c. ESWG: 2015 IPT10 Scope

7. Integrated Marketplace Update .................................................................................. Mr. Bruce Rew

8. Future Meetings ........................................................................................................ Mr. Jim Eckelberger
   BOD – November 4.............................................................. Teleconference
   BOD – December 10.............................................................. Little Rock

2014
   RET/RSC/BOD - January 27-28................................................. Austin
   RET/RSC/BOD - April 28-29.................................................. Oklahoma City
   BOD - June 9-10 ................................................................. Little Rock
   RET/RSC/BOD - July 28-29.................................................. Omaha
   RET/RSC/BOD - October 27-28.......................................... Little Rock
   BOD - December 10.............................................................. Little Rock

Executive Session
**Southwest Power Pool**

**BOARD OF DIRECTORS/MEMBERS COMMITTEE MEETING**

**AND Annual Meeting of Members**

**October 29, 2013**

**ATTENDANCE LIST**

<table>
<thead>
<tr>
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<tbody>
<tr>
<td>Bryce Fremling</td>
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<td>Jack Madden</td>
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Southwest Power Pool
BOARD OF DIRECTORS/MEMBERS COMMITTEE MEETING
AND Annual Meeting of Members
October 29, 2013

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<td>Wendell Deos</td>
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<td>Russ Mihm</td>
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Southwest Power Pool
BOARD OF DIRECTORS/MEMBERS COMMITTEE MEETING
AND Annual Meeting of Members
October 29, 2013

ATTENDANCE LIST

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<tbody>
<tr>
<td>Martha Reine</td>
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<td>David Linton</td>
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<td>Patrick Clay</td>
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<td>Keith Tynes</td>
<td>East Texas</td>
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<tr>
<td>Bernie Zui</td>
<td>Xcel</td>
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</table>
Jon Hansen will act as a proxy at the Board meeting for Mo Doghman with his voting rights this also covers the Annual Meeting of Members.

Thanks,

Christi Labs
Executive Administrative Assistant
Omaha Public Power District
444 South 16th Street Mall, Omaha, NE 68102
402-636-3212
calabs@oppd.com
October 3, 2013

TO WHOM IT MAY CONCERN:

I, Gary R. Roulet, Chief Executive Officer of Western Farmers Electric Cooperative (WFEC), hereby authorize Roy Klusmeyer to represent WFEC and vote on WFEC’s behalf at the Southwest Power Pool Meetings scheduled for October 28 and 29, 2013, in Little Rock, Arkansas.

Sincerely,

[Signature]
Gary R. Roulet
Chief Executive Officer

GRR:jp
Southwest Power Pool
SPECIAL MEETING OF MEMBERS
Southwest Power Pool Corporate Campus, Little Rock, AR
January 29, 2013

Agenda Item 1 – Administrative Items
SPP Board of Directors Chair, Mr. Jim Eckelberger, called the meeting to order at 8:00 a.m. Mr. Eckelberger asked for a round of introductions. There were 114 people in attendance either in person or via phone representing 32 members (Attendance List – Attachment 1). Mr. Nick Brown reported proxies (Proxies – Attachment 2).

Mr. Eckelberger referred to the Annual Meeting of Members minutes from October 30, 2012 (Minutes 10/30/12 – Attachment 3). The minutes were approved by acclamation.

Agenda Item 2 – Corporate Governance Committee Report
Mr. Nick Brown presented the Corporate Governance Committee report (CGC Report – Attachment 4). Mr. Brown stated that there are two vacancies on the Members Committee. In accordance with SPP’s Bylaws, the Corporate Governance Committee nominates candidates to the Membership for consideration and election. The Corporate Governance committee recommends the election of Phil Crissup (OG&E) and Ricky Bittle (AECC) to fill current vacancies on the Members Committee in the Investor-Owned Utility and Cooperatives sectors respectively. If elected, these terms will start immediately and expire at the end of 2014. Nominations for the Members Committee were also entertained from the floor. Hearing none, the Membership was asked to vote. Both nominees were elected.

Adjournment
With no further business, Mr. Eckelberger adjourned the Special Meeting of Members at 8:15 a.m.

Stacy Duckett, Corporate Secretary
Southwest Power Pool, Inc.
CORPORATE GOVERNANCE COMMITTEE
Recommendation to SPP Membership
October 29, 2013

NOMINATIONS TO FILL EXPIRING TERMS
AND ONE VACANCY

Background
Representatives on the Board of Directors, Members Committee and Regional Entity Trustees are elected by the Membership to serve three-year terms.

Analysis
The Corporate Governance Committee is responsible for nominating candidates for the Board of Directors, Members Committee, and Regional Entity Trustees to the Membership for consideration and election at the Annual Meeting of Members.

The following are nominated for three-year terms to commence January 1, 2014:

Board of Directors:    Phyllis Bernard
                        Julian Brix

Members Committee (sector):  Kelly Harrison (IOU)
                               Stuart Solomon (IOU)
                               Noman Williams (Cooperatives)
                               Jeff Knottek (Municipals)
                               Rob Janssen (IPP/Marketers)

Regional Entity Trustees:  John Meyer

Other nominations for the Members Committee may be made from the floor.

In addition to the nominations noted above, Dave Osburn (OMPA) is nominated to fill a current vacancy for the Municipals sector representative. If elected, his term will start immediately and expire at the end of 2014.

Action Requested
Conduct of the elections.

Approved
Corporate Governance Committee     August 29, 2013
Southwest Power Pool
ANNUAL MEETING OF MEMBERS
October 29, 2013

Ballot for
SPP Annual Elections

SPP BOARD OF DIRECTORS:
(All members should vote for 2 nominees)

Recommended by Corporate Governance Committee:

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<tr>
<td></td>
<td></td>
<td>Phyllis Bernard</td>
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<td>Julian Brix</td>
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SPP MEMBERS COMMITTEE:

Each Member should vote for the number of nominees allocated for each sector.

Investor Owned Utilities:
(All members should vote for 2 nominees)

Recommended by Corporate Governance Committee:

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<td>Kelly Harrison (Westar)</td>
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Additional Nominees:

Cooperatives:
(All members should vote for 1 nominee)

Recommended by Corporate Governance Committee:

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<td>Noman Williams (Sunflower)</td>
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Additional Nominees:
Ballot for SPP Membership  
October 29, 2013

Municipals:  
(All members should vote for 2 nominees)

Recommended by Corporate Governance Committee:

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- Jeff Knottek (City Utilities of Springfield)
- Dave Osburn (OMPA) to fill unexpiring term

Additional Nominees:

□ ________________________________
□ ________________________________

IPPs/Marketers:  
(All members should vote for 1 nominee)

Recommended by Corporate Governance Committee:

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- Rob Janssen (Dogwood)

Additional Nominees:

□ ________________________________
□ ________________________________

Small Retail Customer

There are currently no members in this sector.

SPP REGIONAL ENTITY TRUSTEES:  
(All members should vote for 1 nominee)

Recommended by Corporate Governance Committee:

For Against
□ □ John Meyer

MEMBER: ________________________________

REPRESENTATIVE’S SIGNATURE: ________________________________
## SPP Board of Directors

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<td>Nick Brown</td>
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<td>Jim Eckelberger</td>
<td>2015</td>
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<td>Josh Martin</td>
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<td>Harry Skilton</td>
<td>2015</td>
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**Class of 2013**
- Phyllis Bernard
- Julian Brix

**Class of 2014**
- Josh Martin
- Larry Altenbaumer

**Class of 2015**
- Jim Eckelberger
- Harry Skilton
# REGIONAL ENTITY TRUSTEES

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**Class of 2013**  
John Meyer  

**Class of 2014**  
Gerry Burrows  

**Class of 2012**  
Dave Christiano
# SPP Members Committee

<table>
<thead>
<tr>
<th>Sector</th>
<th>Company</th>
<th>Term Expires</th>
</tr>
</thead>
<tbody>
<tr>
<td>Investor Owned Utilities</td>
<td>Kelly Harrison</td>
<td>2013</td>
</tr>
<tr>
<td></td>
<td>Phil Crissup</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Mike Deggendorf</td>
<td>2015</td>
</tr>
<tr>
<td></td>
<td>Stuart Solomon</td>
<td>2013</td>
</tr>
<tr>
<td>Cooperatives</td>
<td>Ricky Bittle</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Gary Roulet</td>
<td>2015</td>
</tr>
<tr>
<td></td>
<td>Noman Williams</td>
<td>2013</td>
</tr>
<tr>
<td></td>
<td>Mike Wise</td>
<td>2015</td>
</tr>
<tr>
<td>Municipals</td>
<td>Jeff Knottek</td>
<td>2013</td>
</tr>
<tr>
<td></td>
<td>vacant</td>
<td>2014</td>
</tr>
<tr>
<td>IPPs/Marketers</td>
<td>Kevin Smith</td>
<td>2015</td>
</tr>
<tr>
<td></td>
<td>Rob Janssen</td>
<td>2013</td>
</tr>
<tr>
<td></td>
<td>Brett Kruse</td>
<td>2014</td>
</tr>
<tr>
<td>State/Federal Agencies</td>
<td>Tom Kent</td>
<td>2015</td>
</tr>
<tr>
<td></td>
<td>Mo Doghman</td>
<td>2014</td>
</tr>
<tr>
<td>Large Retail Customer</td>
<td>vacant</td>
<td>2014</td>
</tr>
<tr>
<td>Small Retail Customer</td>
<td>vacant</td>
<td>2013</td>
</tr>
<tr>
<td>Public Interest/</td>
<td>vacant</td>
<td>2014</td>
</tr>
<tr>
<td>Alternative Power</td>
<td>vacant</td>
<td>2015</td>
</tr>
</tbody>
</table>

## Class of 2013
- Kelly Harrison
- Stuart Solomon
- Noman Williams
- Jeff Knottek
- Rob Janssen
- Sm. Retail (vacant)

## Class of 2014
- Phil Crissup
- Ricky Bittle
- Municipals (vacant)
- Mo Doghman
- Brett Kruse
- Lg. Retail (vacant)
- Publ Int/Alt Pwr (vacant)

## Class of 2015
- Mike Deggendorf
- Gary Roulet
- Mike Wise
- Kevin Smith
- Tom Kent
- Publ Int/Alt Pwr (vacant)
To: SPP Officers / Directors / Managers  
From: Sheri Dunn / Cindy Goodwin  
Date: October 22, 2013  
RE: September 2013 Financial Package  

Attached are the September 2013 monthly financial reports.

1). **Financial Commentary:** Full-Year Actual / Forecast to Budget Variances  

2). **Financial Forecast Overview:** Full-Year Actual / Forecast by month compared to Budget and Prior Year  

3). **Income Statement Actual Results Overview:** Current Month Actual compared to Forecast, YTD Actual compared to Budget and YTD Actual compared to Prior Year  

4). **Balance Sheet:** Current Month compared to Ending Prior Year  

6). **Capital Projects Summary:** Current year and future projections compared to total project Budget  

7). **Headcount Analysis:** Current Month Actual compared to Budget and Final Forecast compared to original Budget  

8). **Job Tracker:** List of current open positions as tracked by Human Resources
2013 Financial Commentary  
September 30, 2013  
(in thousands)

### Summary

<table>
<thead>
<tr>
<th></th>
<th>2013 FY Forecast</th>
<th>2013 FY Budget</th>
<th>Fav/(Unfav)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Revenues</strong></td>
<td>$142,195</td>
<td>$147,015</td>
<td>($4,820) (3.3%)</td>
</tr>
<tr>
<td><strong>Expenses</strong></td>
<td>155,369</td>
<td>162,625</td>
<td>7,257 4.5%</td>
</tr>
<tr>
<td><strong>Net Income/(Loss)</strong></td>
<td>($13,173)</td>
<td>($15,610)</td>
<td>$2,437 15.6%</td>
</tr>
</tbody>
</table>

### Revenue

<table>
<thead>
<tr>
<th></th>
<th>2013 FY Forecast</th>
<th>2013 FY Budget</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tariff Administration Service</td>
<td>$112,592</td>
<td>$113,799</td>
<td>($1,207) 1.1%</td>
</tr>
<tr>
<td>Fees &amp; Assessments *</td>
<td>25,274</td>
<td>28,211</td>
<td>(2,937) (10.4%)</td>
</tr>
<tr>
<td>Contract Services Revenue</td>
<td>424</td>
<td>721</td>
<td>(297) (41.2%)</td>
</tr>
<tr>
<td>Miscellaneous Income</td>
<td>3,905</td>
<td>4,284</td>
<td>(380) (8.9%)</td>
</tr>
<tr>
<td><strong>Total Revenue</strong></td>
<td>$142,195</td>
<td>$147,015</td>
<td>($4,820) 3.3%</td>
</tr>
</tbody>
</table>

* Breakdown of Fees & Assessments:
  - Annual Non-Load Dues: $450, $402, $48 (11.9%)
  - NERC ERO Regional Entity Rev: $9,922, $11,515, ($1,593) (13.8%)
  - FERC Fees & Assessments: $14,903, $16,294, ($2,391) (8.5%)

### Tariff Administration Service

Revenue budget assumed a minimal amount of growth in load history over Jul-2011 thru Aug-2012. Current projections reflect a slight decrease in network and point-to-point service (0.7%), and revenues are expected to be below budget by $1.2M.

### NERC ERO Regional Entity revenue

Revenue is based on expenses incurred by the Regional Entity (RE), which trail budget ($1.6M).

### FERC Schedule 12 revenues

These are billed a month in arrears and based on network transmission. The budget assumed a 3% increase over actual Schedule 12 revenues from Aug-2011 thru Jul-2012. Subsequent to completion of the budget, the 2013 Schedule 12 rate was adjusted down from $0.072 in 2012 to $0.064 for 2013. The forecast has been adjusted with the lower rate, and the expected full-year impact is a $1.4M shortfall compared to the budget.

### Contract Services Revenue

Budget includes revenue for OVEC ($376K) and Entergy Regional Service Committee (ERSC) ($345K). Removal of the ERSC revenues from the forecast created an unfavorable variance in revenue; however, ERSC expenses were also removed from the forecast ($280K). The net ERSC revenue/expense variance is $65K unfavorable for the year. OVEC revenues are forecast at $47K higher than budget, as the contract was renewed at a higher rate beginning in April 2013.

### Miscellaneous Income

This primarily consists of revenues associated with billable resource time related to various studies and other non-recurring income items. The budget assumed costs of the Order 1000 program would be recovered by SPP; however, the revenue has been removed from the forecast given the delay in the FERC ruling and projected start date now targeted for early 2014 ($650K). Revenue for Engineering studies trail budget by $356K.

Partially offsetting the unfavorable variances in Miscellaneous Income are reimbursements for ICT transition services and ICT studies ($392K), ARS reimbursements ($217K), sales tax rebates ($82K) and map sales ($15K), which were not considered in the budget.
### 2013 Financial Commentary
#### September 30, 2013

*(in thousands)*

<table>
<thead>
<tr>
<th>Expense</th>
<th>2013 FY Forecast</th>
<th>2013 FY Budget</th>
<th>Favorable/Unfavorable</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salary &amp; Benefits</td>
<td>$77,053</td>
<td>$77,363</td>
<td>$310</td>
</tr>
<tr>
<td>Assessments &amp; Fees</td>
<td>14,699</td>
<td>16,340</td>
<td>1,641</td>
</tr>
<tr>
<td>Communications</td>
<td>3,636</td>
<td>4,427</td>
<td>790</td>
</tr>
<tr>
<td>Maintenance</td>
<td>11,021</td>
<td>10,476</td>
<td>(545)</td>
</tr>
<tr>
<td>Outside Services (Including RSC)</td>
<td>15,426</td>
<td>16,340</td>
<td>921</td>
</tr>
<tr>
<td>Administrative &amp; Leases</td>
<td>4,397</td>
<td>5,400</td>
<td>1,003</td>
</tr>
<tr>
<td>Travel &amp; Meetings</td>
<td>2,932</td>
<td>4,200</td>
<td>1,267</td>
</tr>
<tr>
<td>Depreciation &amp; Amortization</td>
<td>19,510</td>
<td>20,296</td>
<td>786</td>
</tr>
<tr>
<td>Other Expenses</td>
<td>6,693</td>
<td>7,777</td>
<td>1,084</td>
</tr>
<tr>
<td><strong>Total Expense</strong></td>
<td><strong>$155,369</strong></td>
<td><strong>$162,625</strong></td>
<td><strong>$7,257</strong></td>
</tr>
</tbody>
</table>

**Salaries & Benefits** are projected to be favorable to budget by $310K. Budget calculations for social security did not incorporate the salary cap, and therefore tax expenses are favorable to budget ($352K). Continuing education costs also trail budget and contribute to the favorable variance ($224K). The budget assumed a vacancy rate of 6% (based on historical vacancy levels); however, the forecasted vacancy rate is closer to 3% and cause salaries to exceed budget by $468K. Increased healthcare costs also offset the overall favorable variance ($324K).

For **Communications** expenses, voice circuits / SPPnet frame were budgeted in 2013 based on estimated growth in Market Participants, which has shown no increase to date, and thus contributes to the favorable variance to budget ($790K).

Maintenance exceeds budget by $545K, which relates to items incurred at an earlier date than assumed in the original budget (AIMMS/Cplex license and rentals, and CMT and Netezza Box maintenance). The current full-year maintenance forecast variance to budget is expected to be within 5%.

The **Outside Services** forecast has been reduced in the following areas:
- **Legal** - Removed contingency - SPP determined not to appeal multiple state commission orders in Entergy dockets ($434K)
- **Regional Entity** - 10% reduction reflecting cost containment efforts ($644K)
- **Engineering** - Studies consulting expense trailing budget ($357K)
- **Corporate Services** - Removal of GMAC decommission contingency and on-site medical clinic ($339K)
- **Administration** - Order 1000 start-up costs - delayed until 2014 ($236K)
- **Regional State Committee** - Conferences scaled back ($144K)
- **Market Monitoring** - Staff augmentation ($121K)

Unbudgeted adhoc consulting projects partially offset the favorable variances noted above ($590K). Additionally, outside consulting expense has been added in the Project Management department ($256K). The budget considered all contract project manager costs would be capitalized within the Integrated Marketplace project; however, several contract project managers are working on non-Integrated Marketplace, non-capital projects, and their costs are currently expensed as staff augmentation. Operations staff augmentation also contributes to the offset ($531K).

The favorable **Administrative expense variance** is mainly attributed to utilities and office expenses. The majority of the difference is in utilities ($908K). The utilities expenses were budgeted based on guidance from outside experts prior to occupying the facility. Utilities have been considerably less than these original estimates and the forecast has been adjusted to reflect the anticipated expenses for the remainder of the year. Office expenses have considerably decreased from the budget ($337K). This is primarily the result of the consolidation of staff into one facility and the implementation of a centralized process for tracking and ordering supplies. Miscellaneous equipment purchases exceed budget and partially offset the favorable Administrative variance ($184K). These are miscellaneous asset purchases under $1K, which are expensed as they do not meet the $1K capital threshold.

Expenses related to the ERSC were inadvertently left in the budget and account for $244K of the overall favorable variance in **Meetings** expense, which trails budget $686K overall. Other major components of the meetings expense variance are represented in various SPP Working Group meetings ($237K), Training ($171K) and Regulatory ($34K). Corporate Services continues to analyze scheduled meeting expense projections and provides updated forecast estimates as available. **Travel** expenses trail budget across various departments ($582K). Much of the variance is associated with Integrated Marketplace outreach meetings, which are not anticipated to involve staff travel ($151K).

**Depreciation** trails budget year-to-date due to timing of capital purchases and completed projects being placed into service. Other **Expenses** are composed of interest income / expense / capitalization; miscellaneous income / expense; and various other valuation adjustments. Due to their unpredictability, most items are not considered in the budget, including Interest Income, Other Income/Expense (457b adjustment) and valuation adjustments. These items are generally favorable in comparison to the budget. **Capitalized Interest** is impacted by the timing and amount of capital expenditures on significant projects and is expected to be within 1% of the original budget.
### Income

<table>
<thead>
<tr>
<th>Actual</th>
<th>Actual</th>
<th>Actual</th>
<th>Actual</th>
<th>Actual</th>
<th>Actual</th>
<th>Actual</th>
<th>Actual</th>
<th>Fcst</th>
<th>Fcst</th>
<th>Fcst</th>
<th>FY 2013</th>
<th>Variance</th>
<th>FY 2012</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>$9,657</td>
<td>$8,685</td>
<td>$9,571</td>
<td>$9,187</td>
<td>$9,510</td>
<td>$9,365</td>
<td>$9,452</td>
<td>$9,575</td>
<td>$9,252</td>
<td>$9,502</td>
<td>$9,244</td>
<td>$9,503</td>
<td>$112,592</td>
<td>$113,799</td>
<td>$(1,207)</td>
</tr>
</tbody>
</table>

**Tariff Administrative Service**

**Fees & Assessments**

**Contract Services Revenue**

**Miscellaneous Income**

| **Total Income** | 12,473 | 11,363 | 11,409 | 11,532 | 11,770 | 11,546 | 12,279 | 12,471 | 11,821 | 11,862 | 11,606 | 12,062 | 142,195 | 147,015 | $(4,820) | 147,919 | $(5,724) |

### Expense

<table>
<thead>
<tr>
<th>Expense</th>
<th>Salary &amp; Benefits</th>
<th>Employee Travel</th>
<th>Administrative</th>
<th>Assessments &amp; Fees</th>
<th>Meetings</th>
<th>Communications</th>
<th>Leases</th>
<th>Maintenance</th>
<th>Services</th>
<th>Regional State Committee</th>
<th>Depreciation &amp; Amortization</th>
<th>Total Expense</th>
</tr>
</thead>
<tbody>
<tr>
<td>$6,286</td>
<td>$6,457</td>
<td>$6,321</td>
<td>$6,523</td>
<td>$6,365</td>
<td>$6,123</td>
<td>$6,365</td>
<td>$6,223</td>
<td>$6,290</td>
<td>$6,504</td>
<td>$7,053</td>
<td>$1,469</td>
<td>$11,635</td>
</tr>
</tbody>
</table>

**Over / (Under) Budget**


NRR Over / (Under) Recovery $1,205 $(426) $(1,928) $(37) $770 $(3,342) $572 $456 $(2,071) $397 $287 $(2,348) $(6,465) $(7,967) $1,502 $(4,549) $(11,014)

* Seven positions have been eliminated from the forecast (see detail on Headcount Analysis). Total for 2013 is 596, with 11 positions expected to be open at 12/31/2013.
## Southwest Power Pool
### Actual Results Overview
#### September 30, 2013

### (in thousands)

#### Income

<table>
<thead>
<tr>
<th></th>
<th>Current Month Compared to Forecast</th>
<th>YTD Actual Compared to YTD Budget</th>
<th>YTD 2013 Compared to YTD 2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Sep-2013 Actual</td>
<td>Sep-2013 Forecast</td>
<td>Variance</td>
</tr>
<tr>
<td>Tariff Administrative Service</td>
<td>$9,252</td>
<td>$9,298</td>
<td>($46)</td>
</tr>
<tr>
<td>Fees &amp; Assessments</td>
<td>2,221</td>
<td>2,077</td>
<td>144</td>
</tr>
<tr>
<td>Contract Services Revenue</td>
<td>36</td>
<td>36</td>
<td>-</td>
</tr>
<tr>
<td>Miscellaneous Income</td>
<td>312</td>
<td>322</td>
<td>(10)</td>
</tr>
<tr>
<td><strong>Total Income</strong></td>
<td>$11,821</td>
<td>$11,733</td>
<td>88</td>
</tr>
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</table>

#### Expense

<table>
<thead>
<tr>
<th></th>
<th>Current Month Compared to Forecast</th>
<th>YTD Actual Compared to YTD Budget</th>
<th>YTD 2013 Compared to YTD 2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Sep-2013 Actual</td>
<td>Sep-2013 Forecast</td>
<td>Variance</td>
</tr>
<tr>
<td>Salary</td>
<td>4,596</td>
<td>4,591</td>
<td>(5)</td>
</tr>
<tr>
<td>Benefits &amp; Taxes</td>
<td>2,008</td>
<td>1,877</td>
<td>(131)</td>
</tr>
<tr>
<td>Continuing Education</td>
<td>68</td>
<td>74</td>
<td>7</td>
</tr>
<tr>
<td>Salary &amp; Benefits</td>
<td>6,671</td>
<td>6,542</td>
<td>(129)</td>
</tr>
<tr>
<td>Employee Travel</td>
<td>153</td>
<td>149</td>
<td>(4)</td>
</tr>
<tr>
<td>Administrative</td>
<td>726</td>
<td>175</td>
<td>(551)</td>
</tr>
<tr>
<td>Assessments &amp; Fees</td>
<td>1,213</td>
<td>1,213</td>
<td>-</td>
</tr>
<tr>
<td>Meetings</td>
<td>73</td>
<td>86</td>
<td>13</td>
</tr>
<tr>
<td>Communications</td>
<td>307</td>
<td>308</td>
<td>1</td>
</tr>
<tr>
<td>Leases</td>
<td>16</td>
<td>16</td>
<td>-</td>
</tr>
<tr>
<td>Maintenance</td>
<td>946</td>
<td>905</td>
<td>(42)</td>
</tr>
<tr>
<td>Services</td>
<td>1,095</td>
<td>1,109</td>
<td>14</td>
</tr>
<tr>
<td>Regional State Committee</td>
<td>17</td>
<td>29</td>
<td>11</td>
</tr>
<tr>
<td>Depreciation &amp; Amortization</td>
<td>1,594</td>
<td>1,675</td>
<td>81</td>
</tr>
<tr>
<td><strong>Total Expense</strong></td>
<td>$12,813</td>
<td>$12,208</td>
<td>(605)</td>
</tr>
</tbody>
</table>

#### Other Income/(Expense)

<table>
<thead>
<tr>
<th></th>
<th>Current Month Compared to Forecast</th>
<th>YTD Actual Compared to YTD Budget</th>
<th>YTD 2013 Compared to YTD 2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Sep-2013 Actual</td>
<td>Sep-2013 Forecast</td>
<td>Variance</td>
</tr>
<tr>
<td>Gain or Loss on Sale of Fixed Asset</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other Income / Expense</td>
<td>44</td>
<td>-</td>
<td>(44)</td>
</tr>
<tr>
<td>Interest Income</td>
<td>31</td>
<td>-</td>
<td>(31)</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>(884)</td>
<td>(875)</td>
<td>9</td>
</tr>
<tr>
<td>Capitalized Interest</td>
<td>675</td>
<td>665</td>
<td>(9)</td>
</tr>
<tr>
<td>Change in Valuation of Swap</td>
<td>142</td>
<td>-</td>
<td>(142)</td>
</tr>
<tr>
<td><strong>Net Other Income (Expense)</strong></td>
<td>7</td>
<td>(210)</td>
<td>(217)</td>
</tr>
</tbody>
</table>

#### Net Income (Loss)

<table>
<thead>
<tr>
<th></th>
<th>Sep-2013 Actual</th>
<th>Sep-2013 Budget</th>
<th>Variance</th>
<th>Sep-2013 Actual</th>
<th>Sep-2012 Actual</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>($985)</td>
<td>($685)</td>
<td>($300)</td>
<td>($9,349)</td>
<td>($10,860)</td>
<td>$1,512</td>
<td>($9,349)</td>
</tr>
</tbody>
</table>

#### Headcount

<table>
<thead>
<tr>
<th></th>
<th>Sep-2013</th>
<th>Sep-2012</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>578</td>
<td>583</td>
<td>(5)</td>
<td>578</td>
</tr>
</tbody>
</table>
Southwest Power Pool
Balance Sheet
September 30, 2013
(in thousands)

<table>
<thead>
<tr>
<th></th>
<th>9/30/2013</th>
<th>12/31/2012</th>
<th>Net Change</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ASSETS</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current Assets</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash &amp; Equivalents</td>
<td>$42,791</td>
<td>$95,693</td>
<td>($52,902)</td>
</tr>
<tr>
<td>Restricted Cash Deposits</td>
<td>40,230</td>
<td>43,743</td>
<td>(3,513)</td>
</tr>
<tr>
<td>Accounts Receivable (net)</td>
<td>18,929</td>
<td>17,923</td>
<td>1,006</td>
</tr>
<tr>
<td>Other Current Assets</td>
<td>7,720</td>
<td>5,412</td>
<td>2,309</td>
</tr>
<tr>
<td>Total Current Assets</td>
<td>$109,671</td>
<td>$162,771</td>
<td>($53,100)</td>
</tr>
<tr>
<td>Total Fixed Assets</td>
<td>195,808</td>
<td>173,752</td>
<td>22,056</td>
</tr>
<tr>
<td>Total Other Assets</td>
<td>1,583</td>
<td>2,029</td>
<td>(446)</td>
</tr>
<tr>
<td>Investments</td>
<td>1,157</td>
<td>968</td>
<td>189</td>
</tr>
<tr>
<td><strong>TOTAL ASSETS</strong></td>
<td>$308,219</td>
<td>$339,520</td>
<td>($31,300)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>LIABILITIES &amp; EQUITY</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liabilities</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current Liabilities</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accounts Payable (net)</td>
<td>$8,990</td>
<td>$9,831</td>
<td>(841)</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>41,091</td>
<td>43,914</td>
<td>(2,824)</td>
</tr>
<tr>
<td>Current Maturities of LT Debt</td>
<td>18,736</td>
<td>12,700</td>
<td>6,036</td>
</tr>
<tr>
<td>Other Current Liabilities</td>
<td>20,246</td>
<td>28,742</td>
<td>(8,496)</td>
</tr>
<tr>
<td>Deferred Revenue</td>
<td>6,367</td>
<td>6,286</td>
<td>81</td>
</tr>
<tr>
<td>Total Current Liabilities</td>
<td>95,429</td>
<td>101,472</td>
<td>(6,043)</td>
</tr>
<tr>
<td>Long Term Liabilities</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>US Bank Floating Senior Note - 2014</td>
<td>1,375</td>
<td>5,500</td>
<td>(4,125)</td>
</tr>
<tr>
<td>US Bank 5.45% Senior Notes - 2016</td>
<td>10,500</td>
<td>15,000</td>
<td>(4,500)</td>
</tr>
<tr>
<td>US Bank Maumelle Mortgage - 2027</td>
<td>3,598</td>
<td>3,752</td>
<td>(154)</td>
</tr>
<tr>
<td>Campus 4.82% Senior Notes - 2042</td>
<td>63,229</td>
<td>64,006</td>
<td>(777)</td>
</tr>
<tr>
<td>Integrated Marketplace 3.55% Senior Note - 2024</td>
<td>66,500</td>
<td>70,000</td>
<td>(3,500)</td>
</tr>
<tr>
<td>Senior Notes - 2024</td>
<td>97,500</td>
<td>100,000</td>
<td>(2,500)</td>
</tr>
<tr>
<td>Other Long Term Liabilities</td>
<td>10,167</td>
<td>10,519</td>
<td>(352)</td>
</tr>
<tr>
<td>Total Long Term Liabilities</td>
<td>252,869</td>
<td>268,777</td>
<td>(15,908)</td>
</tr>
<tr>
<td>Net Income</td>
<td>(9,349)</td>
<td>(1,306)</td>
<td>(8,043)</td>
</tr>
<tr>
<td>Members’ Equity</td>
<td>(30,728)</td>
<td>(29,422)</td>
<td>(1,306)</td>
</tr>
<tr>
<td><strong>Total Members’ Equity</strong></td>
<td>(40,077)</td>
<td>(30,728)</td>
<td>(9,349)</td>
</tr>
<tr>
<td><strong>TOTAL LIABILITIES &amp; EQUITY</strong></td>
<td>$308,219</td>
<td>$339,520</td>
<td>($31,300)</td>
</tr>
</tbody>
</table>
## SOUTHWEST POWER POOL
### 2013 - 2015 FORECAST
#### CAPITAL COST PROJECTIONS

### Existing / Carryover Projects

<table>
<thead>
<tr>
<th>Project</th>
<th>2013 Budget</th>
<th>Q1 2013</th>
<th>Q2 2013</th>
<th>Q3 2013</th>
<th>Q4 2013</th>
<th>2013 Forecast</th>
<th>2014 Forecast</th>
<th>2015 Forecast</th>
<th>Prior Year(s)</th>
<th>TOTAL PROJECT FORECAST</th>
<th>TOTAL PROJECT BUDGET</th>
<th>Over/(Under) Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>IT Netezza Upgrade</td>
<td>$2,263</td>
<td>$1,592</td>
<td>$-</td>
<td>$-</td>
<td>$650</td>
<td>$2,242</td>
<td>$177</td>
<td>$120</td>
<td>$519</td>
<td>$3,057</td>
<td>$3,038</td>
<td>$19</td>
</tr>
<tr>
<td>Centralized Modeling (CMT &amp; MCST)</td>
<td>355</td>
<td>308</td>
<td>63</td>
<td>52</td>
<td>73</td>
<td>497</td>
<td>-</td>
<td>-</td>
<td>2,011</td>
<td>2,508</td>
<td>2,455</td>
<td>53</td>
</tr>
<tr>
<td>EMS Marketplace Readiness</td>
<td>361</td>
<td>80</td>
<td>93</td>
<td>100</td>
<td>166</td>
<td>440</td>
<td>48</td>
<td>-</td>
<td>353</td>
<td>841</td>
<td>714</td>
<td>126</td>
</tr>
<tr>
<td>New ICCP Architecture-closed</td>
<td>311</td>
<td>66</td>
<td>65</td>
<td>45</td>
<td>-</td>
<td>175</td>
<td>-</td>
<td>-</td>
<td>355</td>
<td>530</td>
<td>665</td>
<td>(135)</td>
</tr>
<tr>
<td>Ops Automation DC Ties-closed</td>
<td>200</td>
<td>29</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>29</td>
<td>-</td>
<td>-</td>
<td>29</td>
<td>58</td>
<td>332</td>
<td>(274)</td>
</tr>
<tr>
<td>Ops Automation OATI -closed</td>
<td>100</td>
<td>-</td>
<td>15</td>
<td>-</td>
<td>15</td>
<td>-</td>
<td>-</td>
<td>15</td>
<td>30</td>
<td>180</td>
<td>150</td>
<td></td>
</tr>
<tr>
<td>High Availability *</td>
<td>-</td>
<td>153</td>
<td>(30)</td>
<td>-</td>
<td>123</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>123</td>
<td>-</td>
<td>-</td>
<td>123</td>
</tr>
<tr>
<td>Credit Stacking Tool *</td>
<td>-</td>
<td>42</td>
<td>100</td>
<td>-</td>
<td>142</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>142</td>
<td>-</td>
<td>142</td>
</tr>
<tr>
<td>Software (including HR upgrade, other) *</td>
<td>-</td>
<td>(27)</td>
<td>27</td>
<td>31</td>
<td>-</td>
<td>31</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>31</td>
<td>-</td>
<td>31</td>
</tr>
<tr>
<td>Facility *</td>
<td>-</td>
<td>173</td>
<td>25</td>
<td>43</td>
<td>240</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>240</td>
<td>-</td>
<td>240</td>
<td></td>
</tr>
<tr>
<td><strong>Total Existing / Carryover</strong></td>
<td>$3,590</td>
<td>$2,415</td>
<td>$343</td>
<td>$286</td>
<td>$889</td>
<td>$3,933</td>
<td>$225</td>
<td>$120</td>
<td>$3,282</td>
<td>$7,560</td>
<td>$7,385</td>
<td>$175</td>
</tr>
</tbody>
</table>

The Netezza Upgrade and EMS Marketplace Readiness projects are expected to come within 2% of the original budget.

The Centralized Modeling Tool / Model Change Submission Tool project began in mid-2011. The project scope has evolved as the Integrated Marketplace development has been underway. The current estimate includes post go-live support and puts the project at $53K over the original estimates.

New ICCP Architecture hardware/software purchase planned for 2013 was purchased in 2012 at a lower cost, causing the favorable variance to the budget.

The Ops Automation project costs are less than budget for various reasons. For the OATI project, a number of items were removed from the scope after the project was budgeted, and several other items were already part of OATI functionality, requiring only configuration and testing efforts. The scope changes were related to items in which the savings in manual effort did not justify the cost of automation. For the DC Ties project, much of the requirements development and testing, originally assumed to be performed by outside consultants, was performed by SPP staff.

* See notes on next page
### SOUTHWEST POWER POOL
#### 2013 - 2015 FORECAST
#### CAPITAL COST PROJECTIONS

<table>
<thead>
<tr>
<th>Project</th>
<th>2013 Project Forecast</th>
<th>2014 Forecast</th>
<th>2015 Forecast</th>
<th>Prior Year(s)</th>
<th>TOTAL PROJECT FORECAST</th>
<th>TOTAL PROJECT BUDGET</th>
<th>Over/(Under) Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Availability</td>
<td>$ 5,120</td>
<td>$1,598</td>
<td>$ 123</td>
<td>$1,721</td>
<td>Credit Stacking Tool</td>
<td>$ 295</td>
<td>$ 126</td>
</tr>
</tbody>
</table>

* The 2012 Extension items were budgeted for and initially expected to have been completed in 2012.

The PRPC closed out the High Availability project at the end of 2012, as it was originally assumed to be complete. Some of the additional expense recorded in 2013 was reclassified to IT foundation in Q2. Miscellaneous Facility expenses from the 2012 budget were incurred in 2013, including final payments due for interior walls, copy room cabinetry and audio/visual equipment. The final retainage was paid to the contractor in March ($100K).

2012 Extension projects - prior estimates not carried into 2013 budget:

<table>
<thead>
<tr>
<th>Project</th>
<th>Original Budget</th>
<th>2012 Ending Bal</th>
<th>2013 Activity</th>
<th>Final Proj Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Availability</td>
<td>$ 5,120</td>
<td>$1,598</td>
<td>$ 123</td>
<td>$1,721</td>
</tr>
<tr>
<td>Credit Stacking Tool</td>
<td>$ 295</td>
<td>$ 126</td>
<td>$ 142</td>
<td>$ 268</td>
</tr>
<tr>
<td>Facility</td>
<td>$88,553</td>
<td>$83,872</td>
<td>$ 240</td>
<td>$84,112</td>
</tr>
</tbody>
</table>
### SOUTHWEST POWER POOL

#### 2013 - 2015 FORECAST

**CAPITAL COST PROJECTIONS**

<table>
<thead>
<tr>
<th>Project</th>
<th>2013 Budget</th>
<th>Q1 2013</th>
<th>Q2 2013</th>
<th>Q3 2013</th>
<th>Q4 2013</th>
<th>2013 Forecast</th>
<th>2014 Forecast</th>
<th>2015 Forecast</th>
<th>Prior Year(s)</th>
<th>TOTAL PROJECT FORECAST</th>
<th>TOTAL PROJECT BUDGET</th>
<th>Over/(Under) Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>IT Data Center Migration Phase II</td>
<td>$620</td>
<td>$380</td>
<td>$240</td>
<td>$620</td>
<td>$570</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>$1,190</td>
<td>$1,190</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Aurea (IT Progress) ESB Replacement</td>
<td>$50</td>
<td>$50</td>
<td>$100</td>
<td>$531</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>$681</td>
<td>$950</td>
<td>(269)</td>
<td>-</td>
</tr>
<tr>
<td>IT Portal</td>
<td>$498</td>
<td>$76</td>
<td>$50</td>
<td>$91</td>
<td>$217</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>$217</td>
<td>$498</td>
<td>(281)</td>
<td>-</td>
</tr>
<tr>
<td>ETSE 3.0 Transmission Settlements (2015)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>$3,775</td>
<td>$3,775</td>
<td>$3,775</td>
<td>$3,500</td>
<td>275</td>
<td>-</td>
</tr>
<tr>
<td>OPS DTS Upgrade to TTSE (2015)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>$4,400</td>
<td>$4,400</td>
<td>$4,400</td>
<td>$2908</td>
<td>$1,492</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>IT EMS upgrade (2014-2015)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>$1,297</td>
<td>$399</td>
<td>$1,696</td>
<td>$1,696</td>
<td>$2,000</td>
<td>(304)</td>
<td>-</td>
</tr>
<tr>
<td>Integration of IssueTrak with Remedy (2014)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>$1,297</td>
<td>$399</td>
<td>$1,696</td>
<td>$1,696</td>
<td>$1,696</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total New Projects</strong></td>
<td>$1,168</td>
<td>$76</td>
<td>$430</td>
<td>$381</td>
<td>$887</td>
<td>$1,967</td>
<td>$9,105</td>
<td>$11,958</td>
<td>$11,958</td>
<td>$11,196</td>
<td>762</td>
<td>-</td>
</tr>
</tbody>
</table>

**NOTE:** Budget amounts represent estimates established in the original 2013 - 2015 budget. Many of the future year(s) calculations during the 2013 budget cycle are considered rough-order-of-magnitude (ROM) estimates, as the estimates were determined before the project scopes were defined. Forecast numbers represent updated estimates included in the 2014 - 2016 budget.

Projects for the IT Data Center Migration and IT Progress EBS Replacement (recently changed to Aurea EBS Replacement), which carry over into 2014, were recently approved by SPP Executives to be included in the 2014 budget. The projects are scheduled to begin in 2013, and forecasts have been updated based on recently submitted 2014 budget data.

The IT Portal project forecast was reduced by $281K. Although all consulting was budgeted as capital expense, part of the work expected does not qualify as capitalized expense, (i.e. documenting guidelines, training employees and defining processes).

All other new projects are still on target to begin in 2014 or 2015, and forecasts have been updated based on recently submitted 2014 budget data.
## SOUTHWEST POWER POOL
### 2013 - 2015 FORECAST
#### CAPITAL COST PROJECTIONS

<table>
<thead>
<tr>
<th>Project</th>
<th>2013 Budget</th>
<th>Q1 2013</th>
<th>Q2 2013</th>
<th>Q3 2013</th>
<th>Q4 2013</th>
<th>2013 Forecast</th>
<th>2014 Forecast</th>
<th>2015 Forecast</th>
<th>Prior Year(s)</th>
<th>Total Project Forecast</th>
<th>Total Project Budget</th>
<th>Over/(Under) Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Integrated Marketplace / CBA</td>
<td>$21,006</td>
<td>$9,565</td>
<td>$8,443</td>
<td>$7,848</td>
<td>$10,243</td>
<td>$36,098</td>
<td>$6,215</td>
<td>$71,048</td>
<td>$113,360</td>
<td>$112,535</td>
<td>$825</td>
<td></td>
</tr>
<tr>
<td>Consolidated Balancing Authority</td>
<td>756</td>
<td>304</td>
<td>5</td>
<td>135</td>
<td>30</td>
<td>474</td>
<td>-</td>
<td>-</td>
<td>1,900</td>
<td>2,374</td>
<td>2,477</td>
<td>(103)</td>
</tr>
<tr>
<td>Total Integrated Marketplace / CBA</td>
<td>$21,762</td>
<td>$9,869</td>
<td>$8,448</td>
<td>$7,983</td>
<td>$10,273</td>
<td>$36,572</td>
<td>$6,215</td>
<td>$72,948</td>
<td>$115,734</td>
<td>$115,012</td>
<td>$722</td>
<td></td>
</tr>
<tr>
<td>Mitigating Offer Data Submission System *</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>380</td>
<td>240</td>
<td>620</td>
<td>570</td>
<td>-</td>
<td>-</td>
<td>1,150</td>
<td>1,150</td>
<td>-</td>
</tr>
<tr>
<td>IM Capitalized Interest (not included in balance)</td>
<td>$2,724</td>
<td>$800</td>
<td>$719</td>
<td>$675</td>
<td>$577</td>
<td>$2,770</td>
<td>$641</td>
<td>-</td>
<td>-</td>
<td>$3,088</td>
<td>$6,499</td>
<td></td>
</tr>
</tbody>
</table>

The IM project is currently forecasted at $722K more than the board approved target of $115 million. This is an unfavorable movement of approximately $450K from the August 31st report. Significant changes from the prior month include the following:

- Addition of unbudgeted Accenture resources for integration services, market, performance testing and market trials ($348K additional expense)
- Reduction in Alstom CBA forecast for RTGEN and DTS ($185K savings)
- Addition of unbudgeted servers to address MCE performance issues ($176K additional expense)
- Unbudgeted Accenture SME to provide ongoing support ($147K additional expense)

* The Mitigating Offer Data Submission System project is a web page for market participants to submit required cost data to Market Monitoring Unit (MMU) and is a FERC ordered regulatory requirement to be completed by the March 2014 go-live date. The project costs were included in the request for additional funding for the Integrated Marketplace, and are reflected in the IM project total of $115M.
## SOUTHWEST POWER POOL
### 2013 - 2015 FORECAST
#### CAPITAL COST PROJECTIONS

<table>
<thead>
<tr>
<th>Project</th>
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<th>Q1 2013</th>
<th>Q2 2013</th>
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<th>TOTAL PROJECT FORECAST</th>
<th>TOTAL PROJECT BUDGET</th>
<th>Over/(Under) Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined Cycle Enhancements</td>
<td>$207</td>
<td>$</td>
<td>$</td>
<td>$32</td>
<td>$175</td>
<td>$207</td>
<td>$5,069</td>
<td>$70</td>
<td>$</td>
<td>$5,346</td>
<td>$3,800</td>
<td>$1,546</td>
</tr>
<tr>
<td>Regulation Compensation (FERC Order 755)</td>
<td>384</td>
<td>-</td>
<td>-</td>
<td>24</td>
<td>360</td>
<td>384</td>
<td>2,229</td>
<td>301</td>
<td>-</td>
<td>2,914</td>
<td>3,785</td>
<td>(871)</td>
</tr>
<tr>
<td>Long-Term TCRs (LTTCRs)</td>
<td>429</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>91</td>
<td>91</td>
<td>3,912</td>
<td>112</td>
<td>-</td>
<td>4,115</td>
<td>1,510</td>
<td>2,605</td>
</tr>
<tr>
<td>Market to Market</td>
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<td>-</td>
<td>-</td>
<td>21</td>
<td>423</td>
<td>444</td>
<td>5,400</td>
<td>511</td>
<td>-</td>
<td>6,356</td>
<td>1,416</td>
<td>4,940</td>
</tr>
<tr>
<td>AFC Granularity Changes for TSRs (2014)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1,363</td>
<td>-</td>
<td>1,363</td>
<td>1,363</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Sunset Clause for Load Submittal Legacy BAs (2014)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>156</td>
<td>-</td>
<td>156</td>
<td>156</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Assets Pseudo-Tying Out of SPP BA (2014)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>99</td>
<td>99</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>130</td>
<td>(31)</td>
</tr>
<tr>
<td>Marketplace Data for MPs Post Go-Live (2014)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>50</td>
<td>-</td>
<td>50</td>
<td>50</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total Market Post Go-Live</strong></td>
<td>$1,492</td>
<td>$</td>
<td>$</td>
<td>$78</td>
<td>$1,148</td>
<td>$1,226</td>
<td>$16,610</td>
<td>$2,563</td>
<td>$</td>
<td>$20,399</td>
<td>$12,210</td>
<td>$8,188</td>
</tr>
</tbody>
</table>

Market Post Go-Live projects were recommended by the Project Review & Prioritization Committee (PRPC) and approved by Executives for inclusion in the 2014 budget. Forecasts for 2013 - 2015 have been updated to reflect new estimates.

**NOTE:** Budget amounts represent estimates established in the original 2013 - 2015 budget. Many of the future year(s) calculations during the 2013 budget cycle were considered rough-order-of-magnitude (ROM) estimates, as the estimates were determined before the project scopes were defined. Forecast numbers represent updated estimates included in the 2014 - 2016 budget.
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<th>Over/(Under) Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations Foundation</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Marketplace &amp; MOS Enhancements (2014-2015)</td>
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<td>44</td>
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<td>310</td>
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<td>530</td>
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<td>1,521</td>
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<td>$ 122</td>
<td>$ 44</td>
<td>$ 138</td>
<td>$ 7</td>
<td>$ 310</td>
<td>$ 1,431</td>
<td>$ 1,280</td>
<td>$ -</td>
<td>$ -</td>
<td>$ 3,021</td>
<td>$ 2,500</td>
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</table>

Due to the Integrated Marketplace (IM) program resources and systems, SPP Operations is focused on IM activities. Any expenditures for the remainder of 2013 Legacy Applications are only reserved for critical unforeseen issues. The $750K budget in 2014 & 2015 is now included in the Post Go-Live Alstom Patches project in the 2014-2016 budget. The 2013 forecast is approximate to the budget. The 2014 and 2015 forecasts have been updated to reflect projections from the 2014 budget cycle.

### Miscellaneous Capital Spend

<table>
<thead>
<tr>
<th>Project</th>
<th>2013 Budget</th>
<th>Q1 2013</th>
<th>Q2 2013</th>
<th>Q3 2013</th>
<th>Q4 2013</th>
<th>2013 Forecast</th>
<th>2014 Forecast</th>
<th>2015 Forecast</th>
<th>Prior Year(s)</th>
<th>TOTAL PROJECT FORECAST</th>
<th>TOTAL PROJECT BUDGET</th>
<th>Over/(Under) Budget</th>
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<tbody>
<tr>
<td>ETS Foundation-Alstom</td>
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<td>$ -</td>
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<td>$ -</td>
<td>$ -</td>
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<td>$ -</td>
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<td>$ 75</td>
<td>$ 75</td>
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<td>-</td>
<td>165</td>
<td>30</td>
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<td>Stochastic Planning</td>
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<tr>
<td>Redundant EnFuzion Node and PSSE Lock Ph 2</td>
<td>23</td>
<td>-</td>
<td>23</td>
<td>-</td>
<td>-</td>
<td>23</td>
<td>-</td>
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<td>ITP Data Repository</td>
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<tr>
<td>Update PROMOD to Server Solution</td>
<td>10</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Total Miscellaneous Capital Spend</td>
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<td>$ 23</td>
<td>$ -</td>
<td>$ -</td>
<td>$ 23</td>
<td>$ 240</td>
<td>$ 105</td>
<td>$ -</td>
<td>$ -</td>
<td>$ 368</td>
<td>$ 703</td>
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</table>

There are no PRRs necessitating changes to the EIS market at this time; therefore, the ETS Foundation project forecast for 2013 has been removed. Forecasts for 2014 - 2015 have been updated based on recently submitted 2014 budget data.

FERC made a ruling on Order 1000 Regional RFP in mid-July. SPP is proposing additional clarifications, and adjustments will be made to upcoming forecasts after thorough consideration of the impacts associated with the FERC ruling.

Expenses for the Stochastic Planning, ITP Data Repository and PROMOD update projects have been removed from the forecast given the projects are on hold.
### SOUTHWEST POWER POOL
#### 2013 - 2015 FORECAST
##### CAPITAL COST PROJECTIONS

<table>
<thead>
<tr>
<th>Project</th>
<th>2013 Budget</th>
<th>Q1 2013</th>
<th>Q2 2013</th>
<th>Q3 2013</th>
<th>Q4 2013</th>
<th>2013 Forecast</th>
<th>2014 Forecast</th>
<th>2015 Forecast</th>
<th>Prior Year(s)</th>
<th>TOTAL PROJECT FORECAST</th>
<th>TOTAL PROJECT BUDGET</th>
<th>Over/(Under) Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>IT Foundation</td>
<td>$7,045</td>
<td>$2,053</td>
<td>$824</td>
<td>$1,367</td>
<td>$3,568</td>
<td>$7,811</td>
<td>9,586</td>
<td>5,746</td>
<td>-</td>
<td>23,143</td>
<td>16,846</td>
<td>$6,297</td>
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</table>

**Totals presented here are for reconciliation purposes only. Foundation budgets are not carried forward; therefore, Project Budget represents current year budget only. IT Foundation section below shows current projections for 2014 & 2015 as determined during the 2014 budget process, and discusses the variances in the 2013 budget vs. forecast.**

**TOTAL CAPITAL COST PROJECTIONS**

<table>
<thead>
<tr>
<th></th>
<th>2013 Budget</th>
<th>Q1 2013</th>
<th>Q2 2013</th>
<th>Q3 2013</th>
<th>Q4 2013</th>
<th>2013 Forecast</th>
<th>2014 Forecast</th>
<th>2015 Forecast</th>
<th>Prior Year(s)</th>
<th>TOTAL PROJECT FORECAST</th>
<th>TOTAL PROJECT BUDGET</th>
<th>Over/(Under) Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>IT Foundation</strong></td>
<td>$35,705</td>
<td>$14,459</td>
<td>$9,757</td>
<td>$10,281</td>
<td>$16,266</td>
<td>$50,762</td>
<td>$36,273</td>
<td>$18,919</td>
<td>$76,230</td>
<td>$182,183</td>
<td>$165,852</td>
<td>$16,331</td>
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</table>

* New 2014 & 2015 Informational only

The Network / Telecom foundation project is forecasted to be over budget mainly due to Juniper equipment which was budgeted in 2012; however, the purchase was delayed until 2013 due to more efficient versions scheduled for release in 2013.

The Service Mgmt Foundation project is expected to be over budget primarily due to the following additions which were not included in the original 2013 budget (1) Remedy Upgrade Project ($345K) and (2) Service Delivery expenses for Event Management upgrade ($103K) and Tripwire licenses ($129K). All expenses were included in the 2012 budget, but not incurred until 2013. Also reflected in this project are additional BMC license ($41k) and Adobe true-up ($24k).
### Southwest Power Pool
Headcount Analysis
September 30, 2013

<table>
<thead>
<tr>
<th></th>
<th>Current Month Actual vs. Budget</th>
<th>Full Year Forecast vs. Budget</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Sep-13</td>
<td>Budget Sep-13</td>
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<tr>
<td>Administration</td>
<td>49</td>
<td>52</td>
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<tr>
<td>Corporate Services</td>
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<td>29</td>
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<tr>
<td>Process Integrity</td>
<td>44</td>
<td>47</td>
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<tr>
<td>Compliance &amp; Market Monitoring</td>
<td>28</td>
<td>31</td>
</tr>
<tr>
<td>SPP Regional Entity</td>
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<td>32</td>
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<tr>
<td>Information Technology</td>
<td>141</td>
<td>143</td>
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<tr>
<td>Markets</td>
<td>6</td>
<td>6</td>
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<tr>
<td>Operations</td>
<td>154</td>
<td>158</td>
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<tr>
<td>Engineering Planning</td>
<td>39</td>
<td>44</td>
</tr>
<tr>
<td>Engineering Other</td>
<td>37</td>
<td>37</td>
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<tr>
<td>Regulatory Policy &amp; General Counsel</td>
<td>23</td>
<td>24</td>
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<tr>
<td><strong>TOTAL HEADCOUNT</strong></td>
<td>578</td>
<td>603</td>
</tr>
</tbody>
</table>

### Forecast vs. Budget

- **Original 2013 End-of-Year Budget**: 603
  - Stochastic Planning positions (on hold) removed from 2013 forecast: (2)
  - Government Affairs backfill positions removed from 2013 forecast: (2)
  - Settlement Analyst backfill position removed from 2013 forecast: (1)
  - Eliminated backfill for Dec 2012 resignation (RE part-time clerk): (1)
  - Eliminated duplicate Engineering position: (1)
- **Revised 2013 End-of-Year Total Positions**: 596
  - Estimated OPEN positions as of 12/31/2013: 11
- **Estimated ACTIVE positions as of 12/31/2013**: 585
<table>
<thead>
<tr>
<th>Req. #</th>
<th>Position</th>
<th>Dept #</th>
<th>Dept Name</th>
<th>Status</th>
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</thead>
<tbody>
<tr>
<td>12-024</td>
<td>Sr. Compliance Specialist</td>
<td>130</td>
<td>RE - Compliance</td>
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<tr>
<td>12-088</td>
<td>Engineer II</td>
<td>440</td>
<td>GI Studies</td>
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<tr>
<td>12-104</td>
<td>Manager</td>
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<td>Regulatory</td>
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<tr>
<td>12-105</td>
<td>Regulatory Analyst III</td>
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<td>Regulatory</td>
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</tr>
<tr>
<td>12-126</td>
<td>Sr. Business Analyst</td>
<td>510</td>
<td>IT Apps-Data Mgmt</td>
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</tr>
<tr>
<td>12-129</td>
<td>Engineer II</td>
<td>460</td>
<td>Economic Planning</td>
<td></td>
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<tr>
<td>12-130</td>
<td>Sr. Engineer</td>
<td>410</td>
<td>Steady State Planning</td>
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<tr>
<td>12-080</td>
<td>IT Specialist II</td>
<td>510</td>
<td>IT Apps-Reliability</td>
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<tr>
<td>12-100</td>
<td>Engineer II</td>
<td>850</td>
<td>Modeling &amp; Data Integrity</td>
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<td>Sr. VP, Govermental Affairs</td>
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<td>Officers</td>
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<td>12-134</td>
<td>Supervisor, Reliability Coordination</td>
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<td>Systems Operations</td>
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<td>Market Design Analyst I/Engineer I</td>
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<td>Systems Operations</td>
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<td>12-132</td>
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<td>13-006</td>
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<td>13-007</td>
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<td>Reliability Tariff/Scheduling</td>
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<td>Sr. Tariff Administrator, IM</td>
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<td>Market Analyst I, IM</td>
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<td>Legal</td>
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<td>Government Affairs</td>
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<tr>
<td>13-025</td>
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<td>13-028</td>
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<td>Status</td>
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<td>Engineering Spec Studies / Resource Planning</td>
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<td>13-030</td>
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<td>IT Applications, Data Management</td>
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<td>IT Applications</td>
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<tr>
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<tr>
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<td>Systems Administration</td>
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<td>Ops Quality Assurance</td>
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<tr>
<td>13-027</td>
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<td>Interregional Affairs</td>
<td><img src="https://www.emojione.com/chr/1f50c/" alt="✓" /></td>
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<tr>
<td>13-046</td>
<td>Lead Compliance Analyst</td>
<td>230</td>
<td>SPP Compliance</td>
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</tr>
<tr>
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<td>450</td>
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<tr>
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<tr>
<td>13-060</td>
<td>Manager, IT Sourcing</td>
<td>500</td>
<td>Information Technology</td>
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<tr>
<td>13-061</td>
<td>OIT (chg’d from Operator II)</td>
<td>820</td>
<td>Systems Operations</td>
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<td>13-xxx</td>
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<td>400</td>
<td>Eng R&amp;D</td>
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<td>13-054</td>
<td>Business Analyst II</td>
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<td>IT Apps &amp; Requirements Testing</td>
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</tbody>
</table>

Remaining 2012 Positions in Blue: 12-xxx

2013 Budgeted Positions Highlighted in Grey: 13-001 thru 13-023

Replacement Positions Highlighted in Yellow: 13-024 thru 13-xxx

<p>| 2013 YTD Budgeted Positions Filled | 16 |
| 2013 YTD Replacement Positions Filled | 21 |
| 2013 YTD Total Hires | 37 |
| 2012 Positions Filled in 2013 | 20 |
| Total Positions Filled | 57 |</p>
<table>
<thead>
<tr>
<th>Req. #</th>
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**Status Legend**

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<tr>
<td>Inactive</td>
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<tr>
<td>Active, Not Posted</td>
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<tr>
<td>Active, Posted</td>
<td>13</td>
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<tr>
<td>Filled</td>
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**Hire Legend**

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<td>7</td>
<td>18</td>
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<td>External</td>
<td>26</td>
<td>13</td>
<td>39</td>
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<tr>
<td>Total</td>
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09/30 Ending Active Headcount 578

- 2012 Open 3
- 2013 Open 15

2013 Total Positions (Open & Active) 596
Southwest Power Pool
Corporate Metrics

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Transmission & Market Indicators
1 Congestion
2 Regional Control Performance
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4 EIS Prices and Price Range
5 Revenue Neutrality Uplift
6 Market Liquidity

Financial Metrics
7 SPP Admin Fee performance
8 Budget Performance Monitor
9 Financial Settlement Index
10 Financial Disputes Index

Learning & Growth
11 Employee Turnover
12 Recruiting

Performance
13 SPP Regional Entity Compliance
14 IT System Performance
15 Strategic Plan Progress
16 Studies

Metrics Definitions

Supplement - Regulatory Activity Update & Outlook

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SPP shall have no liability to recipients of this information or third parties for the consequences arising from errors or discrepancies in this information, or for any claim, loss or damage of any kind or nature whatsoever arising out of or in connection with (i) the deficiency or inadequacy of this information for any purpose, whether or not known or disclosed to the authors, (ii) any error or discrepancy in this information, (iii) the use of this information, or (iv) a loss of business or other consequential loss or damage whether or not resulting from any of the foregoing.
1b. Congestion - Curtailments

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<td>51.9</td>
<td>83.1</td>
<td>99.1</td>
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<td>Market (Schedules) Curtailments</td>
<td>202.5</td>
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<td>% Tags/Schedules Curtailed</td>
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<td>0.73%</td>
<td>0.69%</td>
<td>1.13%</td>
<td>0.87%</td>
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<td>0.39%</td>
<td>0.18%</td>
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<td>0.34%</td>
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<table>
<thead>
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<th>2010</th>
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<td>Market Curtailments</td>
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<td>% Tags/Schedules Curtailed</td>
<td>134</td>
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<td>Total Tags/Schedules</td>
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- Transmission & Market Indicators
- GWh Curtailed
- % Tags/Schedules Curtailed

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1c. Congestion - TLR / CME Time

Transmission & Market Indicators

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<td>Level 3A</td>
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<td>364</td>
<td>443</td>
<td>467</td>
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<td>138</td>
<td>361</td>
<td>327</td>
<td>359</td>
<td>166</td>
<td>177</td>
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<td>227</td>
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<td>34</td>
<td>11</td>
<td>18</td>
<td>11</td>
<td>22</td>
<td>9</td>
<td>14</td>
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<td>41</td>
<td>77</td>
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<td>11</td>
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<td>1</td>
<td>6</td>
<td>6</td>
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<td>4</td>
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<tr>
<td>Total TLR Time</td>
<td>723</td>
<td>566</td>
<td>600</td>
<td>605</td>
<td>429</td>
<td>175</td>
<td>492</td>
<td>526</td>
<td>416</td>
<td>198</td>
<td>255</td>
<td>157</td>
<td>323</td>
<td>457</td>
<td>593</td>
<td>1,246</td>
<td>697</td>
<td>517</td>
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<td>CME Time (loading &gt;90%)</td>
<td>2,665</td>
<td>2,192</td>
<td>2,207</td>
<td>2,965</td>
<td>2,483</td>
<td>2,523</td>
<td>2,206</td>
<td>1,519</td>
<td>2,147</td>
<td>2,474</td>
<td>1,791</td>
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<td>2,370</td>
<td>847</td>
<td>1,315</td>
<td>2,276</td>
<td>2,424</td>
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1d. Congestion - Congested Intervals

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</thead>
<tbody>
<tr>
<td>Uncongested Intervals</td>
<td>13%</td>
<td>3%</td>
<td>12%</td>
<td>7%</td>
<td>14%</td>
<td>28%</td>
<td>28%</td>
<td>34%</td>
<td>9%</td>
<td>4%</td>
<td>22%</td>
<td>13%</td>
<td>8%</td>
<td>1%</td>
<td>8%</td>
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<tr>
<td>Intervals with Binding Only</td>
<td>79%</td>
<td>92%</td>
<td>82%</td>
<td>81%</td>
<td>80%</td>
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<td>83%</td>
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<td>81%</td>
<td>86%</td>
<td>94%</td>
<td>86%</td>
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<td>Intervals with a Breach</td>
<td>8%</td>
<td>5%</td>
<td>6%</td>
<td>12%</td>
<td>6%</td>
<td>4%</td>
<td>3%</td>
<td>5%</td>
<td>8%</td>
<td>9%</td>
<td>5%</td>
<td>7%</td>
<td>6%</td>
<td>5%</td>
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Interval = 5 minutes

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<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>12 mo</th>
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</thead>
<tbody>
<tr>
<td>Uncongested Intervals</td>
<td>30.8%</td>
<td>23.8%</td>
<td>14.5%</td>
<td>14.5%</td>
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<tr>
<td>Intervals with Binding Only</td>
<td>63.8%</td>
<td>71.8%</td>
<td>79.2%</td>
<td>79.2%</td>
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<tr>
<td>Intervals with a Breach</td>
<td>5.4%</td>
<td>4.4%</td>
<td>6.3%</td>
<td>6.3%</td>
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Average
1e. Price Contour Map (July-September 2013)
1f. Price Contour Map - last 12 months (October 2012 - September 2013)
<table>
<thead>
<tr>
<th>Region</th>
<th>Flowgate Name</th>
<th>Flowgate Location (kV)</th>
<th>Avg Hourly Shadow Price ($/MWh)</th>
<th>Total % Intervals Congested</th>
<th>Projects Expected to Provide Some Positive Mitigation (Estimated In Service Date – Upgrade Type)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Texas Panhandle</td>
<td>OSGCANBUSDEA</td>
<td>Osage Switch - Canyon East [SPS] [(115) ftlo Bushland - Deaf Smith [SPS] (230)]</td>
<td>$40.57</td>
<td>33.1%</td>
<td>1. Tuco Int. – Woodward 345 kV line (May 2014 - Balanced Portfolio) 2. Castro County Int. – Newhart 115 kV line (April 2015 - Regional Reliability) 3. Tuco Int. – Amoco – Hobbs 345 lines (Currently on hold – ITP10)</td>
</tr>
<tr>
<td></td>
<td>SPSNORTH_STH</td>
<td>5 element PTDF flowgate north to south through west Texas</td>
<td>$4.01</td>
<td>16.1%</td>
<td>1. Randall County Interchange – Amarillo South Interchange 230 kV line (May 2013)</td>
</tr>
<tr>
<td></td>
<td>SHAXFRELKKXR</td>
<td>Shamrock Xfmr (115/69) [CSWS] ftlo Elk City Xfmr (230/138) [WFEC]</td>
<td>$2.51</td>
<td>1.3%</td>
<td>1. Elk City – Gracemont 345 kV line (March 2018 – ITP10)</td>
</tr>
<tr>
<td></td>
<td>PENMUN87TCRA</td>
<td>Pentagon – Mund (115) [WR] ftlo 87th Street – Craig (345) [WR-KCPL]</td>
<td>$14.56</td>
<td>10.8%</td>
<td>1. Tap existing Swissvale – Stilwell 345 kV line at West Gardner (in service December 2012) 2. Iatan – Nashua 345 kV line (June 2015 - Balanced Portfolio)</td>
</tr>
<tr>
<td></td>
<td>PENMUNSTRCRA</td>
<td>(see note below)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kansas City - Omaha Corridor</td>
<td>EASXFREASSTJ</td>
<td>Eastowne Xfmr (345/161) ftlo Eastowne-St. Joe (345) [GMOC]</td>
<td>$5.93</td>
<td>4.1%</td>
<td>1. Iatan – Nashua 345 kV line (June 2015 - Balanced Portfolio)</td>
</tr>
<tr>
<td></td>
<td>LAKALASTJHW</td>
<td>Lake Road – Alabama [GMOC] (161) ftlo St. Joe – Hawthorn [GMOC] (345)</td>
<td>$2.26</td>
<td>0.9%</td>
<td>1. Axtell – Post Rock – Spearville 345 kV line, two Spearville – Comanche – Flat Ridge - Woodward 345 kV lines, and two Flat Ridge – Wichita 345 kV lines (Dec 2014 - Balanced Portfolio/Priority Projects) 2. Iatan – Nashua 345 kV line (June 2015 - Balanced Portfolio) 3. Nebraska City – Maryville – Sibley 345 kV line (June 2017 - Priority Projects) 4. Eastowne Transformer (345/161) and decommission of Lake Road – Alabama 161 kV line (May 2013 – sponsored upgrade)</td>
</tr>
<tr>
<td>Eastern Oklahoma</td>
<td>TAHH59MUSFTS</td>
<td>Tahlequah-Highway 59 (161) [GRDA-OGE] ftlo Muskogee-Fort Smith (345) [OGE]</td>
<td>$3.22</td>
<td>1.0%</td>
<td>1. Muskogee – Seminole 345kV (December 2013 - Balanced Portfolio)</td>
</tr>
<tr>
<td>SE Kansas</td>
<td>NEORIVNEODEL</td>
<td>Neosho - Riverton (161) ftlo Neosho - Delaware (345) [WR-EDE-CSWS]</td>
<td>$2.82</td>
<td>2.6%</td>
<td>1. Shipe Road – East Rogers 345 kV (June 2016 - Regional Reliability)</td>
</tr>
<tr>
<td>Tulsa Area</td>
<td>OKMHENOKMKEL</td>
<td>Okmulgee – Henryetta (138) ftlo Okmulgee – Kelco (138) [CSWS]</td>
<td>$2.70</td>
<td>1.2%</td>
<td>1. Muskogee – Seminole 345kV (December 2013 - Balanced Portfolio)</td>
</tr>
</tbody>
</table>

Note: PENMUN87TCRA replaced PENMUNSTRCRA on 4/1/13. Their history has been combined and is reflected as one entry on this table.
### Transmission & Market Indicators

**2a. Regional Control Performance - CPS1 Compliance**

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</thead>
<tbody>
<tr>
<td>&gt;150%</td>
<td>5</td>
<td>7</td>
<td>5</td>
<td>7</td>
<td>6</td>
<td>7</td>
<td>4</td>
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<td>6</td>
<td>9</td>
<td>7</td>
<td>6</td>
<td>4</td>
<td>4</td>
<td>6</td>
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<tr>
<td>100%-150%</td>
<td>15</td>
<td>13</td>
<td>15</td>
<td>13</td>
<td>14</td>
<td>13</td>
<td>16</td>
<td>13</td>
<td>15</td>
<td>13</td>
<td>14</td>
<td>14</td>
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<td>13</td>
<td>13</td>
<td>16</td>
<td>16</td>
<td>14</td>
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<tr>
<td>&lt;100%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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</tbody>
</table>

- BA's with a CPS1 value of <100% are non-compliant
- Violation if any 1 Balancing Authority has an average over the 12 month period of less than 100%
### 2b. Regional Control Performance - CPS2 Compliance

#### Transmission & Market Indicators

**Average Violation if any 1 Balancing Authority has a violation in a 12 month period.**

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</thead>
<tbody>
<tr>
<td>&gt;95%</td>
<td>13</td>
<td>16</td>
<td>16</td>
<td>18</td>
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<td>17</td>
<td>18</td>
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<td>15</td>
<td>17</td>
<td>17</td>
<td>17</td>
<td>15</td>
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<tr>
<td>90-95%</td>
<td>7</td>
<td>4</td>
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<td>7</td>
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<tr>
<td>&lt;90%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>0</td>
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<td>-</td>
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</tr>
</tbody>
</table>

*BA’s with a CPS2 value of <90% are non-compliant*
### 3d. Transmission Service Requests

#### Table: 3d. Transmission Service Requests

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013 (Jan-Sep)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Confirmed</td>
<td>Refused</td>
<td>Confirmed</td>
<td>Refused</td>
</tr>
<tr>
<td>Hourly</td>
<td>20,411</td>
<td>8,475</td>
<td>30,473</td>
<td>9,525</td>
</tr>
<tr>
<td>Daily</td>
<td>9,218</td>
<td>25,949</td>
<td>19,098</td>
<td>13,676</td>
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<tr>
<td>Weekly</td>
<td>789</td>
<td>3,277</td>
<td>4,723</td>
<td>520</td>
</tr>
<tr>
<td>Monthly</td>
<td>16,686</td>
<td>52,977</td>
<td>54,967</td>
<td>104,685</td>
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<tr>
<td>Yearly</td>
<td>630,697</td>
<td>32,055</td>
<td>724,067</td>
<td>107,103</td>
</tr>
<tr>
<td>Total</td>
<td>677,801</td>
<td>122,733</td>
<td>765,249</td>
<td>239,993</td>
</tr>
</tbody>
</table>
4a. EIS Price and Price Range - for three months ending September 2013

Transmission & Market Indicators

| MP Max | 134  | 71   | 117  | 72   | 119  | 74   | 97   | 167  | 82   | 65   | 61   | 65   | 165  | 122  | 98   | 199  | 73   | 74   | 271  | 144  | 102  | 74   | 142  | 81   | 56   |
| Volatility | 36% | 33% | 56% | 34% | 46% | 34% | 27% | 40% | 40% | 35% | 33% | 35% | 58% | 55% | 42% | 60% | 33% | 34% | 64% | 58% | 28% | 35% | 56% | 34% | 32% |

SPP Avg LIP = $25.95
SPP Volatility 34%
4b. EIS Price and Price Range - for 12 months ending September 2013

- Price and Price Range:

- Volatility:
  - 41%, 43%, 59%, 43%, 45%, 39%, 40%, 43%, 48%, 43%, 41%, 41%, 59%, 58%, 42%, 67%, 40%, 40%, 60%, 66%, 42%, 44%, 58%, 42%, 40%

Transmission & Market Indicators

LIP ($/MWh)

- MP Volatility
- SPP Avg LIP = MP Avg LIP
- SPP Volatility
### Monthly Avg LIP ($/MWh)

<table>
<thead>
<tr>
<th>Year</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013*</th>
</tr>
</thead>
<tbody>
<tr>
<td>LIP</td>
<td>49.42</td>
<td>53.21</td>
<td>27.89</td>
<td>31.33</td>
<td>29.28</td>
<td>22.29</td>
<td>25.89</td>
</tr>
</tbody>
</table>

### PEPL Gas Cost ($/MMBtu)

<table>
<thead>
<tr>
<th>Year</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Cost</td>
<td>6.15</td>
<td>7.12</td>
<td>3.31</td>
<td>4.17</td>
<td>3.89</td>
<td>2.64</td>
<td>3.54</td>
</tr>
</tbody>
</table>

* through first nine months of 2013
Revenue Neutrality Uplift (RNU) ensures settlement payments/receipts for each hourly settlement interval equal zero.

- Positive RNU - SPP receives insufficient revenue and collects from market participants.
- Negative RNU - SPP receives excess revenue, which must be credited back to market participants.
### 6a. Market Liquidity - Offered and Dispatchable

#### Transmission & Market Indicators

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Dispatchable MW</td>
<td>17,693</td>
<td>16,938</td>
<td>14,833</td>
<td>12,266</td>
<td>11,792</td>
<td>12,857</td>
<td>13,613</td>
<td>12,903</td>
<td>12,455</td>
<td>11,360</td>
<td>12,351</td>
<td>16,077</td>
<td>17,028</td>
<td>16,991</td>
<td>15,443</td>
<td>11,221</td>
<td>12,738</td>
<td>13,693</td>
<td>13,761</td>
</tr>
<tr>
<td>% of Total Offered</td>
<td>42%</td>
<td>43%</td>
<td>45%</td>
<td>44%</td>
<td>44%</td>
<td>43%</td>
<td>44%</td>
<td>45%</td>
<td>45%</td>
<td>43%</td>
<td>45%</td>
<td>43%</td>
<td>45%</td>
<td>45%</td>
<td>44%</td>
<td>33.1%</td>
<td>39.7%</td>
<td>43.1%</td>
<td>44.1%</td>
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</table>

#### Monthly Average

<table>
<thead>
<tr>
<th>MW (daily average)</th>
<th>Dispatchable MW</th>
<th>Total Offered MW</th>
<th>% of Total Offered</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>17,693</td>
<td>42,357</td>
<td>42%</td>
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<tr>
<td></td>
<td>16,938</td>
<td>39,584</td>
<td>43%</td>
</tr>
<tr>
<td></td>
<td>14,833</td>
<td>33,311</td>
<td>45%</td>
</tr>
<tr>
<td></td>
<td>12,266</td>
<td>27,697</td>
<td>44%</td>
</tr>
<tr>
<td></td>
<td>11,792</td>
<td>26,998</td>
<td>44%</td>
</tr>
<tr>
<td></td>
<td>12,857</td>
<td>29,629</td>
<td>43%</td>
</tr>
<tr>
<td></td>
<td>13,613</td>
<td>30,762</td>
<td>44%</td>
</tr>
<tr>
<td></td>
<td>12,903</td>
<td>28,789</td>
<td>45%</td>
</tr>
<tr>
<td></td>
<td>12,455</td>
<td>27,415</td>
<td>45%</td>
</tr>
<tr>
<td></td>
<td>11,360</td>
<td>26,215</td>
<td>43%</td>
</tr>
<tr>
<td></td>
<td>12,351</td>
<td>28,411</td>
<td>45%</td>
</tr>
<tr>
<td></td>
<td>16,077</td>
<td>35,764</td>
<td>43%</td>
</tr>
<tr>
<td></td>
<td>17,028</td>
<td>38,706</td>
<td>45%</td>
</tr>
<tr>
<td></td>
<td>16,991</td>
<td>38,976</td>
<td>44%</td>
</tr>
<tr>
<td></td>
<td>15,443</td>
<td>34,699</td>
<td>45%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>% of Total Offered</th>
<th>33.1%</th>
<th>39.7%</th>
<th>43.1%</th>
<th>44.1%</th>
</tr>
</thead>
</table>

#### 12 mo

- 2010: 11,221
- 2011: 12,738
- 2012: 13,693
- 12 mo: 13,761
6b. Market Liquidity - Volume

EIS Market Sales Volumes (average daily volume by month)

Average Daily Sales (MWh) and Average Daily Sales ($000's)

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<tr>
<th></th>
<th></th>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Sales (MWh)</td>
<td>83,253</td>
<td>83,685</td>
<td>71,518</td>
<td>65,963</td>
<td>70,856</td>
<td>65,433</td>
<td>61,724</td>
<td>69,420</td>
<td>68,504</td>
<td>88,415</td>
<td>82,315</td>
<td>84,023</td>
<td>77,024</td>
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<tr>
<td>Sales ($000's)</td>
<td>2,194</td>
<td>2,051</td>
<td>1,480</td>
<td>1,466</td>
<td>1,541</td>
<td>1,583</td>
<td>1,491</td>
<td>1,597</td>
<td>1,799</td>
<td>1,804</td>
<td>2,123</td>
<td>2,178</td>
<td>2,182</td>
<td>1,787</td>
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</table>
## 7. SPP Admin Fee Performance

### Financial Metrics

<table>
<thead>
<tr>
<th>Year</th>
<th>Budgeted Net Revenue Required ($000s)</th>
<th>Budgeted Load (000's)</th>
<th>Budgeted NRR / Budget Load</th>
<th>Approved Admin Fee</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>$44,391</td>
<td>253,489</td>
<td>0.175</td>
<td></td>
</tr>
<tr>
<td>2006</td>
<td>$45,688</td>
<td>258,556</td>
<td>0.177</td>
<td></td>
</tr>
<tr>
<td>2007</td>
<td>$52,819</td>
<td>288,649</td>
<td>0.183</td>
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<tr>
<td>2008</td>
<td>$61,462</td>
<td>312,496</td>
<td>0.197</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>$68,358</td>
<td>333,458</td>
<td>0.205</td>
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<tr>
<td>2010</td>
<td>$78,368</td>
<td>343,000</td>
<td>0.228</td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td>$89,560</td>
<td>353,453</td>
<td>0.253</td>
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</tr>
<tr>
<td>2012</td>
<td>$121,814</td>
<td>360,915</td>
<td>0.338</td>
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<table>
<thead>
<tr>
<th>Year</th>
<th>Actual Net Revenue Required ($000's)</th>
<th>Actual Load (000's)</th>
<th>Actual NRR / Actual Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>$38,714</td>
<td>267,239</td>
<td>0.160</td>
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<tr>
<td>2006</td>
<td>$48,613</td>
<td>286,446</td>
<td>0.160</td>
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<tr>
<td>2007</td>
<td>$47,998</td>
<td>301,098</td>
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<tr>
<td>2008</td>
<td>$58,081</td>
<td>296,135</td>
<td>0.190</td>
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<tr>
<td>2009</td>
<td>$59,837</td>
<td>328,175</td>
<td>0.170</td>
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<tr>
<td>2010</td>
<td>$63,497</td>
<td>333,610</td>
<td>0.195</td>
</tr>
<tr>
<td>2011</td>
<td>$80,841</td>
<td>341,438</td>
<td>0.210</td>
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<tr>
<td>2012</td>
<td>$84,776</td>
<td>361,686</td>
<td>0.255</td>
</tr>
<tr>
<td>2013</td>
<td>$119,515</td>
<td>357,436</td>
<td>0.315</td>
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</table>

### Note: Budgeted 2013 figures cover the entire 2013 calendar year, while actual 2013 figures cover the period through the date of this report.
### 8. Budget Performance Monitor

#### Operating Expense Variance

<table>
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<tr>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>in thousands $</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Budgeted Operating Expense</strong></td>
<td>12,843</td>
<td>12,368</td>
<td>12,083</td>
<td>12,773</td>
<td>12,582</td>
<td>12,811</td>
<td>13,268</td>
<td>12,594</td>
<td>13,307</td>
<td>12,901</td>
<td>12,714</td>
<td>12,852</td>
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<tr>
<td><strong>Actual Operating Expense</strong></td>
<td>11,374</td>
<td>11,977</td>
<td>13,026</td>
<td>11,635</td>
<td>12,405</td>
<td>12,571</td>
<td>12,644</td>
<td>12,156</td>
<td>12,603</td>
<td>12,264</td>
<td>12,217</td>
<td>12,813</td>
</tr>
<tr>
<td><strong>Monthly Variance:</strong></td>
<td>(1,469)</td>
<td>(391)</td>
<td>943</td>
<td>(1,138)</td>
<td>(177)</td>
<td>(240)</td>
<td>(624)</td>
<td>(438)</td>
<td>(704)</td>
<td>(637)</td>
<td>(497)</td>
<td>(39)</td>
</tr>
<tr>
<td><strong>Over Budget / (Under Budget)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>12 month Cumulative Variance:</strong></td>
<td>(1,469)</td>
<td>(1,860)</td>
<td>(917)</td>
<td>(2,055)</td>
<td>(2,232)</td>
<td>(2,472)</td>
<td>(3,096)</td>
<td>(3,534)</td>
<td>(4,238)</td>
<td>(4,875)</td>
<td>(5,372)</td>
<td>(5,411)</td>
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</table>
## 9. Financial Settlement Index

### Financial Metrics

#### Transmission Short Pays

<table>
<thead>
<tr>
<th>in thousands</th>
<th>Oct 12</th>
<th>Nov 12</th>
<th>Dec 12</th>
<th>Jan 13</th>
<th>Feb 13</th>
<th>Mar 13</th>
<th>Apr 13</th>
<th>May 13</th>
<th>Jun 13</th>
<th>Jul 13</th>
<th>Aug 13</th>
<th>Sep 13</th>
<th>12 mo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Short Pays</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$433</td>
<td>$720</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$1,153</td>
</tr>
</tbody>
</table>

#### EIS Market Short Pays

<table>
<thead>
<tr>
<th>in thousands</th>
<th>Oct 12</th>
<th>Nov 12</th>
<th>Dec 12</th>
<th>Jan 13</th>
<th>Feb 13</th>
<th>Mar 13</th>
<th>Apr 13</th>
<th>May 13</th>
<th>Jun 13</th>
<th>Jul 13</th>
<th>Aug 13</th>
<th>Sep 13</th>
<th>12 mo</th>
</tr>
</thead>
<tbody>
<tr>
<td>EIS Market Short Pays</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
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</tbody>
</table>
10a. Financial Disputes Index - $

Settlement Dispute Statistics ($)

<table>
<thead>
<tr>
<th>(Figures in $000's)</th>
<th>Jul 12</th>
<th>Aug 12</th>
<th>Sep 12</th>
<th>Oct 12</th>
<th>Nov 12</th>
<th>Dec 12</th>
<th>Jan 13</th>
<th>Feb 13</th>
<th>Mar 13</th>
<th>Apr 13</th>
<th>May 13</th>
<th>Jun 13</th>
<th>Jul 13</th>
<th>Aug 13</th>
<th>Sep 13</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Disputes</td>
<td>$13.1</td>
<td>$116.8</td>
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<td>$5.4</td>
<td>$36.1</td>
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<td>$104.6</td>
<td>$10.8</td>
<td>$167.9</td>
<td>$27.1</td>
<td>$381.1</td>
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<td>Avg. Dispute Size</td>
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<td>$1.0</td>
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<td>$1.7</td>
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<td>$3.3</td>
<td>$0.3</td>
<td>$4.1</td>
<td>$1.1</td>
<td>$16.6</td>
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<td>Largest single dispute</td>
<td>$6.8</td>
<td>$68.2</td>
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<td>$24.6</td>
<td>$1.5</td>
<td>$0.3</td>
<td>$2.2</td>
<td>$7.2</td>
<td>$1.7</td>
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<td>$34.3</td>
<td>$11.0</td>
<td>$68.2</td>
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</table>

2010 2011 2012 12 mo

- $234.2 $45.2 $61.5 $75.7
- $15.2 $1.3 $2.7 $2.6
- $1611.3 $212.4 $231.8 $68.2

* Annual maximum
10b. Financial Disputes Index

Settlement Dispute Statistics

(Figures in $000's)

<table>
<thead>
<tr>
<th>Month</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>12 mo</th>
</tr>
</thead>
<tbody>
<tr>
<td># Disputes</td>
<td>23</td>
<td>8</td>
<td>36</td>
<td>11</td>
</tr>
<tr>
<td># Resettlements</td>
<td>31</td>
<td>32</td>
<td>31</td>
<td>40</td>
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<tr>
<td>Avg Days Outstanding</td>
<td>33</td>
<td>32</td>
<td>65</td>
<td>28</td>
</tr>
</tbody>
</table>

Financial Metrics

- Monthly Average of Active Disputes
- Average Monthly Resettlements
- Average Days Outstanding

Monthly Average

- 2010: 17.8, 11.7, 27.4
- 2011: 38.1, 8.6, 27.3
- 2012: 24.3, 23.9, 40.5
- 12 mo: 24.8, 25.1, 36.5
11a. Employee Turnover - monthly

Employee Turnover (monthly)

Voluntary TO Rate
0.4% 1.1% 0.2% 0.0% 0.9% 0.2% 0.4% 0.2% 0.2% 0.9% 0.2% 0.3% 0.5% 0.7% 0.9%

Involuntary TO Rate
0.0% 0.0% 0.0% 0.0% 0.0% 0.0% 0.0% 0.0% 0.0% 0.0% 0.0% 0.0% 0.0% 0.2%

Total Turnover
2         6         1         -      5         1         2         1         1         5         1         2         3         4         6

Permanent Employees
549     553     554     562     560     558     563     564     565     566     569     573     575     576     576

Rolling 12-month Turnover Rate

Rolling 12-month Turnover Rate
4.6%  5.3%  5.1%  4.7%  5.2%  5.2%  5.5%  5.1%  5.1%  5.0%  5.0%  4.8%  5.0%  4.6%  5.5%
### 11b. Employee Turnover - annual

#### Table: Annual Turnover Ratio and Employee Count

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Turnover</th>
<th>Total Employees</th>
<th>Turnover Ratio</th>
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<tbody>
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<td>1998</td>
<td>3</td>
<td>39</td>
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</tr>
<tr>
<td>1999</td>
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<tr>
<td>2000</td>
<td>7</td>
<td>73</td>
<td>9.6%</td>
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<td>2001</td>
<td>7</td>
<td>110</td>
<td>6.4%</td>
</tr>
<tr>
<td>2002</td>
<td>10</td>
<td>110</td>
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</tr>
<tr>
<td>2003</td>
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<td>116</td>
<td>6.9%</td>
</tr>
<tr>
<td>2004</td>
<td>8</td>
<td>131</td>
<td>6.1%</td>
</tr>
<tr>
<td>2005</td>
<td>14</td>
<td>245</td>
<td>4.7%</td>
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<tr>
<td>2006</td>
<td>21</td>
<td>295</td>
<td>5.7%</td>
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<td>2007</td>
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<td>345</td>
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<tr>
<td>2008</td>
<td>13</td>
<td>423</td>
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</tr>
<tr>
<td>2009</td>
<td>21</td>
<td>449</td>
<td>3.1%</td>
</tr>
<tr>
<td>2010</td>
<td>20</td>
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<tr>
<td>2012</td>
<td>25</td>
<td>576</td>
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<tr>
<td>2013</td>
<td></td>
<td></td>
<td>5.8%</td>
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</table>

**Note 1:** Total Turnover only includes voluntary and involuntary separations; retirements and interns are not used in the calculation.

**Note 2:** Turnover Ratio is annualized for the current year.
13. SPP Regional Entity Compliance

### Period End Open Caseload

<table>
<thead>
<tr>
<th>Year</th>
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<th>2010</th>
<th>2011</th>
<th>1Q '13</th>
<th>2Q '13</th>
<th>3Q '13</th>
<th>4Q '13</th>
<th>1Q '14</th>
<th>2Q '14</th>
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<td></td>
<td></td>
</tr>
<tr>
<td>New Violations</td>
<td>154</td>
<td>268</td>
<td>245</td>
<td>275</td>
<td>286</td>
<td>220</td>
<td>178</td>
<td>206</td>
<td>207</td>
<td></td>
</tr>
<tr>
<td>Processed by SPP RE</td>
<td>254</td>
<td>239</td>
<td>57</td>
<td>44</td>
<td>34</td>
<td>38</td>
<td>56</td>
<td>46</td>
<td>45</td>
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<tr>
<td>Dismissed by SPP RE</td>
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<td>15</td>
<td>22</td>
<td>84</td>
<td>76</td>
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<tr>
<td>Ending Caseload</td>
<td>268</td>
<td>245</td>
<td>275</td>
<td>286</td>
<td>220</td>
<td>178</td>
<td>206</td>
<td>207</td>
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### Violations

<table>
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<th>2012</th>
<th>1Q 2013</th>
<th>2Q 2013</th>
<th>3Q 2013</th>
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</table>

### Cumulative Violations

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<th>2012</th>
<th>1Q 2013</th>
<th>2Q 2013</th>
<th>3Q 2013</th>
<th>2012</th>
<th>2013</th>
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<tr>
<td>Cumulative Violations</td>
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<td>860</td>
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### 14a. IT System Performance - Monthly Service Availability

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<th>Jun</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Apr</th>
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<th>Jun</th>
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<th>May</th>
<th>Jun</th>
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<tr>
<td>Reliability (EMS)</td>
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<td>99.93</td>
<td>100.00</td>
<td>99.87</td>
<td>99.93</td>
<td>100.00</td>
<td>99.87</td>
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<td>Reliability (ICCP)</td>
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<tr>
<td>Scheduling (RTO_SS)</td>
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<td>99.46</td>
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<tr>
<td>MUI Portal</td>
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<th>Target Threshold (min)</th>
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<th>Aug Uptime %</th>
<th>Sep Uptime %</th>
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</table>

**Legend**
- **GREEN**: Meets or Exceeds Targeted Uptime
- **YELLOW**: unplanned outage below Target Uptime
- **RED**: Unplanned outage below Target Uptime
### 14b. IT System Performance - 12 Month Service Availability

<table>
<thead>
<tr>
<th>%</th>
<th>Market System (MOS)</th>
<th>Reliability (EMS)</th>
<th>Reliability (ICCP)</th>
<th>Tariff Admin (OASIS)</th>
<th>Scheduling (RTO_SS)</th>
<th>COS Portal</th>
<th>MUI Portal</th>
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<tbody>
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<td>12 Month Service Availability</td>
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No update
16a. Studies - Aggregate - MW

### Performance

**2011-AGP1**
- Completed:
  - 3Q 12: 1,401
  - 4Q 12: 1,252
  - 1Q 13: 1,519

**2011-AG2**
- Completed:
  - 3Q 12: 1,401
  - 4Q 12: 1,252
  - 1Q 13: 1,519

**2011-AG3**
- Completed:
  - 3Q 12: 1,401
  - 4Q 12: 1,252
  - 1Q 13: 1,519

**2012-AG1**
- Completed:
  - 3Q 12: 2,834
  - 4Q 12: 2,834

**2012-AG2**
- Completed:
  - 3Q 12: 2,834

**2012-AG3**
- Completed:
  - 3Q 12: 5,733
  - 4Q 12: 5,733
  - 1Q 13: 10,412
  - 2Q 13: 8,423
  - 3Q 13: 8,323

**2013-AG1**
- Completed:
  - 3Q 12: 3,945

**2013-AG2**
- Completed:
  - 3Q 12: 5,974

**TOTAL**
- Completed:
  - 3Q 12: 16,034
  - 4Q 12: 24,783
  - 1Q 13: 17,895
  - 2Q 13: 17,971
  - 3Q 13: 18,897
### Generation Interconnection MW - In Progress

#### Performance

**In Progress**

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<td>Transition Cluster</td>
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<td>DISIS-2012-001</td>
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<td>DISIS-2012-002</td>
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<td>FCS-2012-004</td>
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<td>Pending Withdrawal</td>
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<tr>
<td><strong>TOTAL</strong></td>
<td>13,637</td>
<td>12,060</td>
<td>11,665</td>
<td>11,124</td>
<td>8,652</td>
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</table>
**Metrics Definitions**

**Transmission and Market Indicators**

Two groups of metrics will be monitored to provide an overall health indication of the regional transmission system and market.

- **Reliability Performance Indicators**, which focus on the actual operations of the transmission system and whether or not it was operated within expected limits and standards.
- **Market Performance Indicators**, which focus on the performance of the market in terms of overall volume, prices and level of participation.

The intent is to monitor the trends in these areas over time to identify any unexpected performance in an area. Specific performance targets may be established in the future as experience is gained with the information.

### Reliability Performance Indicators

This sub-group of metrics is designed to measure the operations of the transmission system from a reliability perspective.

- How much time was congested during the period. (see Congestion)
- How much energy was curtailed due to congestion? (see Congestion)
- Was the system operated in compliance with the relevant control performance standards? (see Regional Control Performance)

<table>
<thead>
<tr>
<th>1. Congestion</th>
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<thead>
<tr>
<th>1a. Congestion</th>
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</table>
- Time (in hours) during the month that flowgates were in Congested (Breached or Binding) and Over the Limit
- % of Schedules/Tags Curtailed

<table>
<thead>
<tr>
<th>1b. Curtailments</th>
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</table>
- Tag Curtailments and Market (Schedules) Curtailments along with Total Tags and Schedules.

<table>
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<tr>
<th>1c. TLR / CME Time</th>
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</thead>
</table>
- TLR Events by level (in hours)
  - Level 3 - curtailment of non-firm schedules and non-firm market flow
  - Level 4 – curtailment of all non-firm schedules and non-firm market flow (additional reconfiguration of transmission allowed)
  - Level 5 - curtailment of all non-firm and some firm schedules and market flow
    - "A" Levels begin curtailing at the beginning of the next hour
    - "B" Levels begin curtailing immediately and lasts through the end of the next hour
- CME (Congestion Management Events) where loading is greater than 90% (in hours)

<table>
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<tr>
<th>1d. Congested Intervals</th>
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</thead>
</table>
- Percent of intervals binding (flow = System Operating Limit [SOL]), breached (flow > SOL) and congested (either binding or breached) during the month.

<table>
<thead>
<tr>
<th>1e. &amp; 1f. Price Contour Map</th>
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</table>
- Graphic representation of average monthly prices by load area for the last quarter and last 12 months. Flowgates appearing in the top ten by average shadow price impact in 1g. are identified on 1f.

<table>
<thead>
<tr>
<th>1f. Congestion</th>
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</thead>
</table>
- Congestion by flowgate by average hourly shadow price.
### Regional Control Performance

Measures the aggregate performance to the NERC CPS (Control Performance Standards) of the Balancing Authorities in the region. This indicator is set based on the number of BAs within region that are in compliance with the NERC real time control performance standards (known as BAL-001 – Real Power Balancing Control Performance and BAL-002 – Disturbance Control Performance).

- CPS1 requires BAs to be in compliance for 100% of the periods measured within the month; and
- CPS2 requires BAs to be in compliance for 90% of the periods measured within the month.

For the CPS1 standard, each BA’s rolling 12 month performance is grouped into one of three performance bands (<100% [red], 100-150% [yellow], >150% [green]).

The number of BA’s whose CPS1 score falls into these bands is shown; with below 100% meaning non-compliant with the standard.

- CPS2 performance is depicted in the appropriate bands (<90% [red], 90-95% [yellow], >95% [green]) based on the monthly CPS2 score rather than a rolling 12 month average.

### Market Performance Indicators

This sub-group of indicators provides a view of the effectiveness of the EIS market in the context of answering the following questions:

- What was the value of transmission services used in the month? (see Transmission Utilization)
- What was the average wholesale price paid in the region and what was its volatility? (see EIS Price and Price Range)
- How much Revenue Neutrality Uplift was generated during the month? (see Congestion Uplift)
- What was the level of available generation offered to the market and EIS related energy sales in the month? (see Market Liquidity)

### Transmission Utilization

Measures the volume of transmission service scheduled in the month in terms of the transmission service revenues paid by both Network Customers and Point-to-Point customers.

- The revenues paid by transmission customers are directly related to the amount of transactions scheduled on the transmission system and therefore provide a proxy as to the utilization of the transmission system in the period.
- Transmission service revenues will be reported as a simple sum of revenues paid for Network Service, Firm Point-to-Point, and Non-Firm Point-to-Point transmission service.
- Transmission service MWh will be reported as a simple sum of Network Service, Firm Point-to-Point, and Non-Firm Point-to-Point transmission service.

### Price and Price Ranges

Shows the EIS market prices (high, average and low) for each market participant within the footprint on during the previous 12-month period as well as for the previous month. Also provides an SPP-wide average price for the period reported. Volatility (measured as the coefficient of correlation, which is average divided by the standard deviation) is shown for each market participant as well as SPP as a whole. A higher volatility indicates more variability in prices.

- Shows the SPP-wide monthly average EIS price and the Gas Cost at the Panhandle Eastern Pipeline hub along with 12-month rolling averages.
<table>
<thead>
<tr>
<th></th>
<th>Revenue Neutrality Uplift</th>
<th>Tracks amount of RNU (Revenue Neutrality Uplift) charged or credited to market participants during the month. RNU ensures settlement payments/receipts for each hourly settlement interval equal zero.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• Positive RNU - SPP receives insufficient revenue and collects from market participants.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Negative RNU - SPP receives excess revenue, which must be credited back to market participants.</td>
<td></td>
</tr>
</tbody>
</table>
|   | Market Liquidity                                                                          | Measures the average daily MW offered and dispatchable to the EIS market (dispatchable generation); as well as the average daily sales volume during the month in MWh and dollars. | • Data is taken from the Resource Plans.  
  
  A “percent of total offered” is calculated using the dispatchable MW divided by the total offered MW.  
  
  • Although no specific performance targets have been set, the intent is to monitor the trend of this index to identify significant deviations from average. |
|   | Financial Metrics                                                                          | This group of metrics provides a view of the organization’s overall financial situation in terms of both the operating costs and settlement functions carried out. |• Measures actual costs incurred by SPP on an annual basis and compares this to the approved Admin Fee and Budgeted Net Revenue Requirement (NRR).  
  
  • Measures the total actual operating expenses against the total budgeted operating expenses across the organization.  
  
  • Metric measures the timeliness of the financial settlements for both transmission billing and EIS market billing and provides a proxy for the strength of the organization’s cash flow.  
  
  • Measures the number and value of disputes made with regard to the financial settlements of the markets. The objective in this area is twofold: (1) minimize the time to clear disputes; and (2) minimize the total value of dollars in dispute.  
  
  1. The dollar amount for total disputes, the average dispute size and the largest single dispute is tracked.  
  
  2. The number of disputes active during the month, as well as the average days outstanding for those disputes is calculated. In addition, the number of resettlements during the month is tracked. |
# Learning & Growth Metrics

These indicators provide insights into the organization’s success in maintaining and supporting its desired staffing levels and employee growth plans.

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<tbody>
<tr>
<td>11.</td>
<td>Employee Turnover</td>
</tr>
<tr>
<td></td>
<td>Measures both involuntary and voluntary turnover rates, along with number of employees in the organization. Monthly turnover is charted on a rolling 12 month basis, while annual turnover ratio and number of employees is provided for historical purposes.</td>
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<tr>
<td></td>
<td>A turnover rate is calculated each month by dividing the total turnover for the month by the total employee count at month-end. This monthly rate is then aggregated for the previous 12 months giving a 12-month turnover rate. In order to observe the trend, this 12-month turnover rate is calculated on a rolling basis for the last 25 months.</td>
</tr>
<tr>
<td></td>
<td>An annual turnover rate and the number of employees at year-end are both tracked for historical purposes.</td>
</tr>
<tr>
<td>12.</td>
<td>Staffing</td>
</tr>
<tr>
<td></td>
<td>Measures the number of new hires during a month (positions filled) from internal transfers and external hires. Also shows year-to-date new hire total.</td>
</tr>
</tbody>
</table>

# Performance Metrics

The metrics in this group focus on NERC Compliance and IT System Availability.

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<table>
<thead>
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<tbody>
<tr>
<td>13.</td>
<td>SPP RE Compliance</td>
</tr>
<tr>
<td></td>
<td>Measures SPP Regional Entity compliance of all NERC standards. Metrics track the active caseload, as well as new possible violations and the disposition of reported violations.</td>
</tr>
<tr>
<td>14.</td>
<td>IT System Availability</td>
</tr>
<tr>
<td></td>
<td>Measures availability of SPP IT Systems.</td>
</tr>
<tr>
<td>15.</td>
<td>Strategic Plan Progress</td>
</tr>
<tr>
<td></td>
<td>Tracks status of elements of the SPP Strategic Plan.</td>
</tr>
</tbody>
</table>
## Regulatory Update - Activity in Significant Dockets
### Third Quarter 2013

### SPP Tariff/Governing Document Revisions

<table>
<thead>
<tr>
<th>Docket Number</th>
<th>Short Description</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>ER12-1179</td>
<td>SPP Submission of Tariff Revisions to Implement SPP Integrated Marketplace</td>
<td>On July 31, 2013, SPP submitted an Offer of Settlement and related documents to resolve outstanding issues concerning the treatment of grandfathered agreements (“GFAs”) in the SPP Integrated Marketplace. SPP requested that the Commission approve the settlement by October 31, 2013. On September 20, 2013, FERC issued an Order on Compliance Filing and Proposed Tariff Revisions. The Commission directed SPP to revise various aspects of its Integrated Marketplace proposal and also added some additional requirements for the informational report due fifteen months after the market start date. SPP's compliance filing is due on November 19, 2013. On September 23, 2013, SPP submitted tariff revisions to submit and justify its Virtual Energy Transaction Fee proposed in the Integrated Marketplace Filing consistent with the October 18, 2012 Order. SPP requested that the Commission issue an order on this filing by November 18, 2013. On September 30, 2013, FERC issued an Order Conditionally Approving Settlement in Part, Establishing Further Hearing and Settlement Judge Procedures in Part and Denying Request for Rehearing. The Commission conditionally approved in part the offer of settlement filed on July 31, 2013. However, the Commission severed and established hearing and settlement judge procedures as to the issue concerning whether GFA 494 should be included in Schedule 1 of the Settlement. The Commission found that with the exception of the issue concerning GFA No. 494, the Settlement resolves all other outstanding issues concerning the treatment of GFAs in the Integrated Marketplace. The Commission denied in part and dismissed as moot in part NPPD’s June 19, 2013 Motion for Clarification, or in the Alternative Rehearing. SPP was directed to submit a compliance filing to include a revised settlement agreement reflecting a revision to the standard of review provision. SPP's compliance filing is due on October 30, 2013.</td>
</tr>
<tr>
<td>ER12-2292</td>
<td>SPP Submission of Tariff Revisions to Attachment AE to</td>
<td>On September 20, 2013, FERC issued an Order on Rehearing, Compliance Filing and Waivers.</td>
</tr>
</tbody>
</table>
## SPP Tariff/Governing Document Revisions

<table>
<thead>
<tr>
<th>Docket Number</th>
<th>Short Description</th>
<th>Summary</th>
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<tbody>
<tr>
<td></td>
<td>Facilitate the Systematic Rather than Manual Curtailment of Non-Dispatchable Resources in the Energy Imbalance Services Market (“EIS Market”) During Period of Congestion</td>
<td>The Commission denied Acciona Wind Energy USA LLC's request for rehearing. The Commission granted SPP's request for temporary limited waiver filed on February 13, 2013, to delay implementation of systematic and automated curtailment rules, contained in Section 4.3 of Attachment AE, for new non-dispatchable resources that became commercially operable on or after October 15, 2012. The Commission granted SPP's request for waiver filed on March 18, 2013, to delay implementation of systematic and automated curtailment rules for the Ensign Wind resource for the period from March 19, 2013 to June 1, 2013. The Commission accepted SPP's March 1, 2013 Compliance Filing, effective March 19, 2013, subject to a further compliance filing. On October 10, 2013, SPP submitted its compliance filing in response to the September 20, 2013 Order. SPP also requested a temporary limited Tariff waiver to permit a delay in the implementation of the systematic curtailment of existing Non-Dispatchable Resources (that went into Commercial Operation before October 15, 2012) from September 20, 2013 to September 26, 2013 that was necessary to accommodate required software system changes.</td>
</tr>
<tr>
<td>ER13-366 and ER13-367</td>
<td>SPP Submission of Tariff Revisions to Comply with Order No. 1000 Regional Planning and Cost Allocation Requirements</td>
<td>On July 18, 2013, FERC issued an Order on Compliance Filing, accepting SPP's compliance filing, subject to another compliance filing due on November 15, 2013. An effective date of March 30, 2014 was granted. On September 17, 2013, FERC issued an Order Granting Rehearing for Further Consideration of the July 18, 2013 Order.</td>
</tr>
<tr>
<td>ER13-1768 and ER13-1769</td>
<td>SPP Submission of Tariff Revisions to Attachment AN to Incorporate into the Tariff the Agreement Between Southwest Power Pool, Inc. and Southwest</td>
<td>On August 9, 2013, SPP submitted City of Independence, Missouri's signature page to the SPP BA Agreement. FERC action is pending.</td>
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<tr>
<td>Docket Number</td>
<td>Short Description</td>
<td>Summary</td>
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<tr>
<td>ER13-1914</td>
<td>SPP Submission of Tariff Revisions to Clarify the Determination of Credits and Distribution of Credit Revenue for Creditable Upgrades</td>
<td>On July 9, 2013, SPP submitted tariff revisions to clarify the determination of credits and distribution of credit revenue for Creditable Upgrades under the Tariff, and include provisions that are designed to simplify and streamline the crediting process. An effective date of September 8, 2013 was requested. On September 6, 2013, FERC issued a Deficiency Letter requiring additional information in order to process the filing. On October 7, 2013, SPP filed its response to the Commission's request for additional information issued on September 6, 2013. On October 9, 2013, SPP filed an amendment to its proposed tariff revisions filed on July 9, 2013.</td>
</tr>
<tr>
<td>ER13-1939</td>
<td>SPP Submission of Tariff Revisions to Comply with Order No. 1000 Interregional Coordination and Cost Allocation Requirements</td>
<td>On July 10, 2013, SPP submitted revisions to its Tariff to comply with Order No. 1000's requirements for interregional coordination and cost allocation. SPP requested an effective date for all Tariff revisions submitted herein which is coincident to the effective date the Commission ultimately approves for SPP's Order No. 1000 regional compliance. In its regional compliance filing, SPP requested an effective date of March 30 following the Commission's acceptance of such filing. For Addendum 4 to Attachment O, SPP requested an effective date of the later of March 30 the year after Commission acceptance of SPP's regional planning process, or January 1, 2015. On September 9, 2013, the Southeastern Regional Transmission Planning process (“SERTP”) Sponsors filed a Protest, requesting that the Commission reject SPP's proposed Sections 1.3.2 and 2.1.B and, instead, accept the SERTP's proposed versions. On September 24, 2013, SPP filed an answer in response to the Protest filed by the SERTP Sponsors filed on September 9, 2013. SPP stated that the SERTP Protest misinterprets the Waiver Request and reinforces the need for Commission clarification on the matter, and misinterprets SPP's Testimony.</td>
</tr>
<tr>
<td>ER13-2031</td>
<td>SPP Submission of Revisions to Bylaws and Membership Agreement to Implement Withdrawal Obligations and Revisions to Provide Greater</td>
<td>On July 25, 2013, SPP submitted revisions to its Tariff to clarify the potential responsibility of members that withdraw from SPP for certain penalty costs incurred by SPP prior to the member's withdrawal. SPP submitted related revisions to its Bylaws and Membership Agreement. An effective date of September 23, 2013 was requested.</td>
</tr>
<tr>
<td>Docket Number</td>
<td>Short Description</td>
<td>Summary</td>
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<tr>
<td>ER13-2033</td>
<td>Flexibility Regarding the Functions of Various SPP Committees Reporting to the Board of Directors and Submission of Tariff Revisions to Clarify Withdrawal Obligations</td>
<td>On September 19, 2013, FERC issued an Order on Proposed Revisions to Tariff, Bylaws, and Membership Agreement. The Commission conditionally accepted the proposed revisions for filing, effective September 23, 2013, subject to SPP filing additional revisions. The Commission found that the proposed revisions are unclear regarding whether non-transmission owning members would be obligated for costs of transmission facilities approved before their withdrawal. SPP was directed to file revisions to clarify that the withdrawal obligation for the costs of transmission facilities is limited to transmission owning members. SPP's compliance filing is due on October 21, 2013. On October 4, 2013, SPP filed a Motion for Extension of Time and Request for Expedited Action. SPP requested an extension until November 1, 2013 to submit the compliance filing.</td>
</tr>
<tr>
<td>ER13-2091</td>
<td>SPP Submission of Tariff Revisions to Enhance Market Participation Eligibility Criteria, Clarify Data Sharing with Regulatory Agencies, and Clarify Bilateral Settlement Schedules Related to Certain Integrated Marketplace Rules in Anticipation of SPP's Application for Exemption of Certain Market Transactions from the provisions of the CEA and CFTC</td>
<td>On August 1, 2013, SPP submitted revisions to Attachments X and AE of its Tariff regarding minimum participation criteria set forth in SPP's credit policy, the sharing of Confidential Information relating to SPP's Integrated Marketplace, and the use of Bilateral Settlement Schedules in the Integrated Marketplace in anticipation of SPP's application for exemption of certain market transactions from the provisions of the CEA and CFTC. An effective date of March 1, 2014 was requested. SPP requested that the Commission issue an order on this filing no later than October 1, 2013, so that the rules will be in place in time for certain pre-market implementation activities, including initial allocation of Auction Revenue Rights and Transmission Congestion Rights. On September 30, 2013, FERC issued an Order Conditionally Accepting Tariff Revisions, subject to a compliance filing, to be effective March 1, 2014 as requested. The Commission directed SPP to modify its phrase in section 11.2(3) of Attachment AE to state “from a source other than the Commission or its staff or the CFTC or its staff.” SPP's compliance filing is due on October 30, 2013.</td>
</tr>
<tr>
<td>ER13-2164</td>
<td>SPP Submission of Tariff Revisions to Modify the Aggregate Transmission Service Study (“ATSS”) Process (Aggregate Study Backlog Clearing Process Tariff Revisions)</td>
<td>On August 15, 2013, SPP submitted tariff revisions to revise the ATSS process to allow SPP to close out the backlog of transmission service studies in conjunction with the implementation of the ATSS improvements. An effective date of October 12, 2013 was requested. On September 20, 2013, SPP submitted an answer in response to comments filed by the East Texas Cooperatives in this proceeding. SPP stated: 1) the revised ATSS process for transmission service requests with third-party impacts gives an eligible customer options for proceeding in the ATSS process;</td>
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### SPP Tariff/Governing Document Revisions

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<td>2) the Cooperatives characterization of the revised ATSS process for transmission service requests with third-party impacts is misplaced. SPP also responded to various other comments included in the Cooperatives' September 5, 2013 Comments. On October 11, 2013, FERC issued an Order Conditionally Accepting Tariff Revisions, effective October 12, 2013, subject to a compliance filing. The Commission found SPP's proposal to be just and reasonable as it will allow SPP to process its customers' transmission requests in a more efficient manner and reduce the current queue backlog SPP is facing. However, the Commission directed SPP to submit additional tariff language to clarify the calculation of make-whole payments and cost reallocation under its proposal. SPP's compliance filing is due on November 12, 2013.</td>
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### Other Filings of Interest

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<thead>
<tr>
<th>Docket Number</th>
<th>Short Description</th>
<th>Summary</th>
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</thead>
<tbody>
<tr>
<td>EL11-34 and 12-1158 (U.S. Court of Appeals)</td>
<td>Midcontinent Independent System Operator, Inc. (&quot;MISO&quot;) Petition for Declaratory Order Seeking Commission Confirmation Regarding Section 5.2 of the Joint Operating Agreement (&quot;JOA&quot;) between MISO and SPP</td>
<td>On July 31, 2013, the U.S. Court of Appeals issued an Order scheduling oral argument to be held on October 18, 2013 in Case No. 12-1158. On October 7, 2013, the U.S. Court of Appeals issued an Order allocating times for the oral argument to be held on October 18, 2013.</td>
</tr>
<tr>
<td>ER13-1864</td>
<td>Joint Operating Agreement (&quot;JOA&quot;) between SPP and the Midcontinent Independent System Operator, Inc. (&quot;MISO&quot;) to Include Market-to-Market (&quot;M2M&quot;) Terms and Conditions (SPP Rate Schedule FERC No. 9)</td>
<td>Numerous parties filed Comments or Protests in response to SPP’s June 28, 2013 Filing. On August 5, 2013, SPP filed an answer in response to comments and protests submitted in this proceeding. SPP stated: 1) SPP’s proposed provisions limiting the designation of temporary flowgates as new M2M flowgates are just and reasonable and should be approved; 2) SPP’s requested effective date for implementation of the proposed M2M process is consistent with Commission directives; and 3) nothing in the M2M filing was intended or should be construed as a limitation on SPP or its Transmission Owners' rights to pursue compensation and use issues.</td>
</tr>
<tr>
<td>ER13-1937</td>
<td>Joint Operating Agreement (&quot;JOA&quot;) between SPP and the Midcontinent Independent System Operator, Inc. (&quot;MISO&quot;) to Comply with Interregional Requirements of Order No. 1000 (SPP Rate Schedule FERC No. 9)</td>
<td>On July 10, 2013, SPP submitted revisions to the JOA between SPP and MISO to address the interregional coordination and cost allocation requirements of Order No. 1000. SPP requested an effective date to coincide with the effective date of its Order No. 1000 regional Tariff provisions. In its regional compliance filing, SPP requested an effective date of March 30 following the Commission's acceptance of such filing. On September 24, 2013, SPP filed an answer in response to Protests filed by MISO and the MISO Transmission Owners (&quot;MISO TOs&quot;) on September 9, 2013. SPP stated: 1) the Protesters mischaracterize the merits of SPP's proposal to allocate the costs of interregional transmission projects commensurate with the benefits; and 2) SPP's proposal is superior to the tie-line methodology proposed by the MISO TOs.</td>
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<tr>
<td>Docket Number</td>
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<tr>
<td>Arkansas 10-011-U</td>
<td>In the Matter of a Show Cause Order Directed to Entergy Arkansas, Inc. (“EAI”) Regarding Its Continued Membership in the Current Entergy System Agreement, or Any Successor Agreement Thereto, and Regarding the Future Operation and Control of Its Transmission Assets</td>
<td>On August 12, 2013, EAI filed a Motion for Authorization to Participate in MISO Planning Resource Auction. EAI requested that the Commission grant its Motion to participate in the Midcontinent Independent System Operator, Inc.’s (“MISO”) Planning Resource Auction for the partial planning year of 2013, and to participate on an on-going basis beginning with the annual auction to take place in April 2014 for the 2014-2015 MISO planning year by October 4, 2013. On September 18, 2013, the APSC issued Order No. 77, granting EAI's Motion for Authorization to Participate in MISO Planning Resource Auction. EAI was directed to file an annual report of its participation in MISO's Planning Resource Auction by June 30 each year, beginning on June 30, 2015. On September 18, 2013, the APSC issued Order No. 78, directing EAI and MISO to appear and show cause why the Commission should not find EAI and MISO are in violation of Condition No. 2 of Order No. 68. The Commission found, as a preliminary matter, that EAI's apparent intention to engage in joint transmission planning with the other Entergy Operating Companies appears to be in violation of Conditions 2(a) and 2(b) of Order No. 68. On October 8, 2013, EAI and MISO submitted their responses to Order No. 78.</td>
</tr>
<tr>
<td>Kansas 13-ITCE-677-MIS</td>
<td>In the Matter of the Application of ITC Great Plains, LLC (“ITC”) and Mid-Kansas Electric Company, LLC (“MKEC”) for a</td>
<td>An evidentiary hearing was held on August 6, 2013. On August 27, 2013, the KCC issued an Order Granting Siting Permit. The Commission directed the Applicants to submit quarterly reports detailing the progress and costs of the project and a final report</td>
</tr>
</tbody>
</table>
### State Cases

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<tr>
<th>Docket Number</th>
<th>Short Description</th>
<th>Summary</th>
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<tr>
<td><strong>Siting</strong></td>
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</table>
| Kansas 13-WSEE-676-MIS | Siting Permit for the Construction of a 345 kV Transmission Line in Cloud and Ottawa Counties, Kansas | On September 9, 2013, ITC and MKEC filed a Petition for Clarification of the August 27, 2013 Order Granting Siting Permit. The Applicants stated that paragraph 12 of the Order inaccurately states that the project will continue until spring 2014. The expected in-service date is in 2016.  
On September 17, 2013, the KCC issued an Amended Order Granting Siting Permit. The Commission granted the Applicants' Joint Application for a siting permit to construct an electric transmission line with certain proposed route modifications approved in this Order. |
| **Kansas**          |                                                                                   |                                                                                                                                                                                                                                                                                                                                                                                                   |
An evidentiary hearing was held on August 7, 2013.  
On August 29, 2013, the KCC issued an Order Approving Siting Application. Westar was directed to provide quarterly updates to the Commission on the status of the project.                                                                                                                                                                  |
| **Missouri**        |                                                                                   |                                                                                                                                                                                                                                                                                                                                                                                                   |
On August 28, 2013, Empire filed a Motion for Approval of Stipulation and Agreement.  
On September 11, 2013, the MoPSC issued an Order Granting Motion for Approval of Unanimous Stipulation and Agreement, effective October 11, 2013. Empire's continued participation in SPP shall continue on an interim basis through August 1, 2019. No later than May 1, 2018, Empire shall file a pleading accompanied by a study ("2018 Interim Report"), comparing the costs and estimated benefits of its participation in SPP. |
| **New Mexico**      |                                                                                   |                                                                                                                                                                                                                                                                                                                                                                                                   |
Staff filed Direct Testimony on August 9, 2013.  
The Applicants filed Rebuttal Testimony on August 16, 2013.  
On August 30, 2013, William Grant filed Supplemental Direct Testimony on behalf of SPS, in order to provide supplemental information regarding projected savings and benefits on an annual basis as required in the Certification of Stipulation in Case 07-00390-UT, and whether there have been any service reliability changes as a result of SPS’ participation in the SPP RTO.  
On September 18, 2013, the NMPRC issued a Final Order authorizing SPS to participate in the SPP RTO on a permanent basis, subject to the same terms and conditions as set out in the Final Order in Case No. 07-00390-UT. The procedural schedule was vacated. |
| **Texas**           |                                                                                   |                                                                                                                                                                                                                                                                                                                                                                                                   |
## State Cases

<table>
<thead>
<tr>
<th>Docket Number</th>
<th>Short Description</th>
<th>Summary</th>
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<tr>
<td></td>
<td>Southwestern Public Service Company (&quot;SPP&quot;) (collectively the &quot;Applicants&quot;) for Approval of Purchase and Sale of Facilities, for Approval of Regulatory Accounting Treatment of Gain or Sale, and for Transfer of Certain Rights</td>
<td>On August 19, 2013, SPP filed a Notice of Stipulation and Settlement Agreement entered into by SPP and SPS.</td>
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<td>On August 30, 2013, SPP and SPS filed an Amended Stipulation and Settlement Agreement.</td>
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<td>A hearing was held on September 3, 2013.</td>
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<td>Parties filed Initial Briefs on September 13, 2013.</td>
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<td>On September 20, 2013, the parties filed an Unopposed Stipulation.</td>
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<td>Parties filed Reply Briefs on September 20, 2013.</td>
</tr>
<tr>
<td>State of Missouri</td>
<td>Kansas City Power &amp; Light Company's Interim Period Ends (participation in SPP RTO) (February 24, 2006 Stipulation and Agreement approved by MoPSC on July 13, 2006)</td>
<td>10/1/2013</td>
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<tr>
<td>State of Arkansas</td>
<td>Initial Briefs due by Noon (Order No. 27 issued on September 11, 2013)</td>
<td>10/1/2013</td>
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<tr>
<td>State of Arkansas</td>
<td>Proposed Findings of Fact and Conclusions of Law due by noon (Order No. 27 issued on September 27, 2013)</td>
<td>10/1/2013</td>
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<tr>
<td>FERC</td>
<td>Deficiency Letter Response is due (Deficiency Letter issued on September 6, 2013)</td>
<td>10/7/2013</td>
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<tr>
<td>FERC</td>
<td>Offer Cap Filing due (annual filing) (Docket number TBD)</td>
<td>10/15/2013</td>
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<tr>
<td>United States Court of</td>
<td>Intervenors in Support of Respondent Briefs are due (Order issued by U.S. Court of Appeals on March 5, 10/16/2013</td>
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<tr>
<td>FERC</td>
<td>Reply Briefs due by noon (Order No. 27 issued on September 11, 2013)</td>
<td>10/16/2013</td>
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<tr>
<td>FERC</td>
<td>Each Regional Transmission Organization and Independent System Operator to appear before the Commission in order to share its 10/17/2013</td>
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<tr>
<td>Intervenors in Support of Respondent Briefs are due (Order issued by U.S. Court of Appeals on March 5, 10/16/2013</td>
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<tr>
<td>Each Regional Transmission Organization and Independent System Operator to appear before the Commission in order to share its experiences from the summer and fall. Each RTO and ISO should describe the progress it has made in refining existing practices to provide better coordination between the natural gas and electric industries and ensure adequate fuel supplies. This discussion also should address any natural gas transportation concerns that arise during the winter heating season and should identify any generator outages during the winter and spring that are fuel related (Order Directing Further Conferences and Reports issued November 15, 2012)</td>
<td>10/17/2013</td>
<td></td>
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<tr>
<td>Regulatory Outlook</td>
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<tr>
<td>United States Court of Appeals of the Eleventh Circuit</td>
<td>Oral argument to be held beginning at 9:30 AM Eastern Time before the U.S. Court of Appeals (Order issued July 31, 2013)</td>
<td>10/18/2013</td>
</tr>
<tr>
<td>FERC</td>
<td>Compliance Filing due to clarify that the withdrawal obligation for the costs of transmission facilities is limited to transmission owning members (Order on Proposed Revisions to Tariff, Bylaws, and Membership Agreement issued on September 19, 2013)</td>
<td>10/21/2013</td>
</tr>
<tr>
<td>FERC</td>
<td>Compliance Filing due to clarify that the withdrawal obligation for the costs of transmission facilities is limited to transmission owning members (Order on Proposed Revisions to Tariff, Bylaws, and Membership Agreement issued on September 19, 2013)</td>
<td>10/21/2013</td>
</tr>
<tr>
<td>FERC</td>
<td>Compliance Filing due to revise Section 4.3 of Attachment AE (Order on Rehearing, Compliance Filing and Waivers issued on September 20, 2013)</td>
<td>10/21/2013</td>
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<tr>
<td>FERC</td>
<td>SPP’s Compliance Filing is due to modify Section 11.2(3) of Attachment AE (Order Conditionally Accepting Tariff Revisions issued on September 30, 2013)</td>
<td>10/30/2013</td>
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<tr>
<td>FERC</td>
<td>SPP’s Compliance Filing due to 1) revise Tariff provisions governing the designation of the GFA Responsible Entity; 2) revise scheduling and reporting requirements; and 3) provide additional justification and Tariff revisions related to the proposal to uplift the costs of the GFA carve-out (Order Conditionally Accepting Tariff Revisions issued on September 30, 2013)</td>
<td>10/30/2013</td>
</tr>
<tr>
<td>FERC</td>
<td>SPP to file a revised settlement agreement reflecting a revision to the standard of review provision (Order Conditionally Approving Settlement in Part, Establishing Further Hearing and Settlement Judge Procedures in Part and Denying Request for Rehearing issued on September 30, 2013)</td>
<td>10/30/2013</td>
</tr>
<tr>
<td>FERC</td>
<td>SPP to file its Annual Budget in FERC Docket Nos. ER04-48, ER08-1338, RT04-1</td>
<td>11/1/2013</td>
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<tr>
<td>FERC</td>
<td>Order No. 764 Compliance Filing due to 1) offer intra-hourly transmission scheduling; 2) incorporate provisions into the pro forma Large Generator Interconnection Agreement requiring interconnection</td>
<td>11/12/2013</td>
</tr>
<tr>
<td>FERC</td>
<td>ER13-2164</td>
<td>SPP's Compliance Filing is due to include additional tariff language to clarify the calculation of make-whole payments and cost reallocation for the Aggregate Transmission Service Study process (Order Conditionally Accepting Tariff Revisions issued on October 11, 2013)</td>
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<tr>
<td>United States Court of 12-1232</td>
<td>Reply Briefs are due (Order issued by U.S. Court of Appeals on March 5, 2013)</td>
<td>11/15/2013</td>
</tr>
<tr>
<td>FERC</td>
<td>ER13-366</td>
<td>SPP's Order 1000 Regional Compliance Filing is due (Order on Compliance Filing issued on July 18, 2013)</td>
</tr>
<tr>
<td>FERC</td>
<td>ER13-367</td>
<td>SPP's Order 1000 Regional Compliance Filing is due (Order on Compliance Filing issued on July 18, 2013)</td>
</tr>
<tr>
<td>FERC</td>
<td>ER12-1179</td>
<td>SPP's Integrated Marketplace Compliance Filing is due (Order on Compliance Filing and Proposed Tariff Revisions issued on September 20, 2013)</td>
</tr>
<tr>
<td>FERC</td>
<td>ER13-1173</td>
<td>SPP's Integrated Marketplace Compliance Filing is due (Order on Compliance Filing and Proposed Tariff Revisions issued on September 20, 2013)</td>
</tr>
<tr>
<td>FERC</td>
<td>ER12-1179</td>
<td>SPP to file an informational report documenting its progress toward launch of the Integrated Marketplace (Order on Compliance Filing and Proposed Tariff Revisions issued on September 20, 2013)</td>
</tr>
<tr>
<td>FERC</td>
<td>RM12-16</td>
<td>Effective date of Order No. 785, Final Rule approving Reliability Standards FAC-001-1 (Facility Connection Requirements), FAC-003-3 (Transmission Vegetation Management), PRC-004-2.1a (Analysis and Mitigation of Transmission and Generation Protection System Misoperations), and PRC-005-1.1b (Transmission and Generation Protection System Maintenance and Testing) (Order No. 785 issued on September 19, 2013)</td>
</tr>
</tbody>
</table>
## Regulatory Outlook

<table>
<thead>
<tr>
<th>Date</th>
<th>FERC/State of New Mexico</th>
<th>Description</th>
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<tbody>
<tr>
<td>11/27/2013</td>
<td>AD10-13</td>
<td>Effective date of Order No. 784, Final Rule revising certain aspects of the Commission's current market-based rate regulations, ancillary services requirements under the pro forma open access transmission tariff, and accounting and reporting requirement (Order No. 784 issued on July 18, 2013)</td>
</tr>
<tr>
<td>11/27/2013</td>
<td>RM11-24</td>
<td>Effective date of Order No. 784, Final Rule revising certain aspects of the Commission's current market-based rate regulations, ancillary services requirements under the pro forma open access transmission tariff, and accounting and reporting requirement (Order No. 784 issued on July 18, 2013)</td>
</tr>
<tr>
<td>12/16/2013</td>
<td>10-00143-UT</td>
<td>Lea County Electric Cooperative, Inc. to file Interim Report regarding LCEC's continued participation in the SPP RTO (October 1, 2010 Uncontested Stipulation; December 16, 2010 Final Order Adopting Certification of Stipulation)</td>
</tr>
<tr>
<td>12/31/2013</td>
<td>RM05-5</td>
<td>Each RTO/ISO to revise its Tariff to include the NAESB Energy Efficiency and Phase II Demand Response M&amp;V Standards. For standards that do not require implementing tariff provisions, the Commission will allow the RTO/ISO to incorporate WEQ standards by reference in its Tariff (Order No. 676-G issued February 21, 2013)</td>
</tr>
<tr>
<td>12/31/2013</td>
<td>ER12-1179</td>
<td>SPP to file a certification of readiness for Integrated Marketplace (Order on Compliance Filing and Proposed Tariff Revisions issued on September 20, 2013)</td>
</tr>
<tr>
<td>1/22/2014</td>
<td>RM12-22</td>
<td>NERC to submit one or more Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of geomagnetic disturbances consistent with the reliable operation of the Bulk-Power System (Order No. 779 issued on May 16, 2013)</td>
</tr>
<tr>
<td>2/1/2014</td>
<td>EO-2012-0269</td>
<td>Empire District Electric Company's Interim Period Ends (participation in SPP RTO) (February 24, 2006 Stipulation and Agreement approved by MoPSC on July 13, 2006)</td>
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<tr>
<td><strong>State of Missouri EO-2006-0141</strong>&lt;br&gt;Empire District Electric Company's Interim Period Ends (participation in SPP RTO) (February 24, 2006 Stipulation and Agreement approved by MoPSC on July 13, 2006)</td>
</tr>
<tr>
<td><strong>FERC RM10-12</strong>&lt;br&gt;Commission staff to file a Status Report concerning the use of e-Tag ID data in Electric Quarterly Reports (Order Partially Extending Compliance Effective Date issued February 8, 2013)</td>
</tr>
<tr>
<td><strong>FERC ER06-451</strong>&lt;br&gt;SPP Demand Response Status Report Due</td>
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