1. CALL TO ORDER
2. PRELIMINARY MATTERS
   a. Roll Call and Declaration of a Quorum
   b. Adoption of Minutes from January 25, 2016
3. UPDATES
   a. RSC First Quarter Financial Report
   b. SPP
   c. FERC
4. BUSINESS MEETING
5. CAWG REPORT AND VOTING ITEMS
   a. CAWG Report…………………………………………………………………………………..Dallas Rippy
      This report provides an update on CAWG activity
      i. New Member Cost Allocation Review Process……………………………John Krajewski
         Update on the New Member Cost Allocation Review Process developed by CAWG
      ii. Aggregate Study Waiver Criteria…………………………………………………………..Adam McKinnie
         Update on the CAWG Evaluation of the Aggregate Study Waiver Criteria Evaluation
   b. Capacity Margin Task Force [Voting Item]……………………………Tom Hestermann/Lanny Nickell
      Update on activities of CMPT and consider approval of the policies promulgated by the CMTF
6. REPORTS/PRESENTATIONS
   a. RARTF Update…………………………………………………………………………………..Steve Stoll
      This report will provide an update on the activities of the Regional Allocation Review Task Force.
   b. Integration Transmission Planning Near-Term (ITPNT) Assessment ……………………. Lanny Nickell
      This report will update the RSC on the 2016 ITPNT Assessment and Report
   c. Seams Update…………………………………………………………..Carl Monroe
      This report will provide an update on the pending matters at FERC related to SPP’s seams.
   d. Integrated Marketplace Update………………………………………………………………Bruce Rew
      This report will update the RSC on the Integrated Marketplace.
   e. Transmission Planning Improvement Task Force Update…………………………………Brian Gedrich
      This report will provide an update on the activities of the Transmission Planning Improvement Task Force
7. OTHER RSC MATTERS
8. ACTION ITEMS
9. SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS

RSC Meetings:

July 18, 2016 – Dallas, TX
October 24, 2016 – Little Rock, AR

10. ADJOURN

* NOTE: ADDITIONAL INFORMATIONAL MATERIAL ATTACHED

Attached to the RSC’s meeting agenda and background material is additional material that is either for informational or reporting purposes.
Southwest Power Pool
REGIONAL STATE COMMITTEE
Skirvin Hilton, Oklahoma City, OK
January 25, 2016
• MINUTES •

ADMINISTRATIVE ITEMS:

The following members were in attendance:

Patrick Lyons, New Mexico Public Regulation Commission (NMPRC)
Steve Stoll, Missouri Public Service Commission (MOPSC)
Shari Feist Albrecht, Kansas Corporation Commission (KCC)
Lamar Davis, Arkansas Public Service Commission (APSC)
Dennis Grennan, Nebraska Power Review Board (NPRB)
Kristie Fiegen, South Dakota Public Utilities Commission (SDPUC)
Brian Kalk, North Dakota Public Service Commission (NDPSC)
Libby Jacobs, Iowa Utilities Board (IUB)
Dana Murphy, Oklahoma Corporation Commission (OCC)
Donna Nelson, Public Utility Commission of Texas (PUCT)

President Patrick Lyons called the Regional State Committee (RSC) meeting to order at 1:02 p.m. with roll call and a quorum was declared. He then requested introductions of those in attendance. There were 115 in attendance, either in person or via the phone (Attendance & Proxies – Attachment 1). President Lyons thanked everyone for coming and welcomed the newest member Commissioner Dennis Grennan from Nebraska Power Review Board. He took a few minutes to also recognize Commissioner Dana Murphy for her hard work on the RSC last year. President Lyons asked the Commissioners to each take a few minutes to provide a bit of information about themselves, what they are currently working on, and what issues they are facing in their individual states. Each commissioner provided an update and introduced their staff.

The first item of business was the approval of the October 26, 2015 meeting minutes (RSC Minutes 10/26/15 – Attachment 2). Commissioner Kristie Fiegen moved to approve the minutes; Commissioner Lamar Davis seconded. The motion passed unanimously.

UPDATES

RSC Fourth Quarter Financial Report
Mr. Paul Suskie, Southwest Power Pool, Inc. (SPP) Staff provided the financial report (RSC 2015 Q4 Financials – Attachment 3). He noted that everything was on target but over just a bit in the area of travel which was expected due to the two new members.

SPP Report
Mr. Nick Brown, SPP Staff, provided the President’s Report. He began by introducing, Mr. Bruce Scherr and Mr. Graham Edwards, the two nominees for the board that will be voted on at tomorrow’s Special Meeting of Members first thing in the morning. In April of 2015 the Special Meeting of Members approved the recommendation to expand the outside directors’ positions to from six to up to nine. The CGC decided to fill only two of the three positions.
Mr. Brown went on to express his appreciation to the Commissioners and their states for their work as they take on the challenge of the EPA’s Clean Power Plan. SPP has been named to assess the impacts of the implementation planned on the bulk electric network. It is a bold challenge with the uncertainty as to how the individual states are going to comply. You have been instrumental in helping SPP engage with each of the individual states.

Federal Energy Regulatory Commission (FERC) Report
Mr. Patrick Clarey provided the FERC report. The Commission approved a series of orders involving the settlement agreement among MISO, SPP and other parties regarding the integration of Entergy into MISO and compensation for use of SPP’s system. FERC issued a proposal to revise the $1,000 per megawatt-hour cap on supply offers in day-ahead and real-time markets run by regional transmission organizations and independent system operators. FERC staff released a white paper on Guidance Principles for Clean Power Plan Modeling. The white paper identifies four guiding principles that may assist transmission planning entities in conducting effective analysis of the CPP and associated state plans, federal plans or multi-state plans. EEI announced in January that Mr. Phil Moeller will join the organization as senior vice president of Energy Delivery and Chief Customer Solutions Officer. Commissioner Tony Clark announced he will not seek another term on the Commission when his term ends later this year. The US Supreme Court upheld FERC Order No. 745. The Court said FERC acted within its authority in setting rates for Demand Response.

Mr. Clarey thanked Mr. Lanny Nickell and his team for briefing FERC staff on developments in the CMTF looking at changes to SPP’s reserve margin requirements.

BUSINESS MEETING

RSC Budget for 2016
Mr. Paul Suskie presented the Auditor Letter. He reported this is an annual requirement to hire a firm to conduct an audit (Auditor Letter – Attachment 4). Commissioner Steve Stoll made a motion approving Thomas & Thomas, LLP as the auditor for the SPP RSC’s 2015 fiscal year audit, authorizing the preparation of an audit report and the RSC’s Federal Information Return (Form 990), and authorizing RSC President Pat Lyons to sign the engagement letter on behalf of the RSC; Commissioner Shari Feist Albrecht seconded. The motion passed unanimously.

CAWG REPORT AND VOTING ITEMS

CAWG Report
Mr. Dallas Rippy provided the Cost Allocation Working Group (CAWG) report (CAWG Report – Attachment 5). He reviewed meeting dates and subjects discussed. The New Member Cost Allocation process document is in the background materials and available for your review. The final draft should be available for the RSC in April. Mr. Rippy provided updates on the Transmission Planning Improvement Task Force, Capacity Margin Task Force, Z2 project, and the CAWG Aggregate Study Waiver Criteria Evaluation.

REPORTS/PRESENTATIONS

Regional Allocation Review Task Force (RARTF) Update
Commissioner Steve Stoll, provided an update on the RARTF (RARTF Update – Attachment 6). Commissioner Stoll reported on the Regional Cost Allocation Review (RCAR) II update. The committee agreed to leave the Integrated System projects in the Base Case models and to using the 2015-2054 window for RCAR II analysis. The task force also reviewed a draft business practice for the analysis approval and implementation of potential RCAR remedies and agreed to accept the ESWG recommendation for treatment of trapped generation and load pocket modeling issues for RCAR II.

Non-Order 1000 Interregional Cost Allocation Order
Mr. Sam Loudenslager, SPP Staff, reported on the review of FERC Order (Review of FERC Order on Seams Cost Allocation – Attachment 7). Mr. Loudenslager went over the history since 2010 of the efforts by the RSC and SPP stakeholders to develop a cost allocation methodology for seams projects. The Seams Projects Task
Force (SPTF) was initiated in March 2014 to address cost allocation for non-Order 1000 seams projects. The RSC unanimously approved highway funding for all non-Order 1000 seams projects, with a voltage of 100 kV and above, provided that tariff language requires RSC review and input before a vote on such projects by the SPP BOD, if only one SPP zone is found to receive 100% of the SPP allocated benefits. In September 2015, SPP filed tariff revisions that had been approved by the Board of Directors and in November 2015 FERC rejected the filing. FERC addressed the shortcomings of the proposal in its November 2015 order. Staff will talk to FERC staff about the order in the future.

EPA Rule 111(d) Update
Mr. Lanny Nickell, SPP Staff, provided an update on the new Strategic Planning Committee Clean Power Plan Task Force. There has not been any recent quantitative analysis, but some qualitative reports have been produced. One of the reports discusses the implications of a mass-based approach versus a rate-based approach. There is also a report that evaluates the reliability implications of the proposed federal plan. The later was the basis used for comments that SPP filed on January 21st to the EPA. There is a set of talking points that can be used when speaking to groups during outreach. There are thirteen states that SPP has visited and been able to provide information on the CPP.

Capacity Margin Task Force (CMTF)
Mr. Tom Hestermann, Chair of the CMTF provided a report on the CMTF (Capacity Margin Task Force Update – Attachment 8). Mr. Hestermann reviewed the CMTF policy issues to include load responsible entity, planning reserve margin (PRM) requirement, planning reserve assurance policy, and deliverability study. The task force conducted an educational workshop for stakeholders prior to the Markets and Operations Policy Committee (MOPC). There will be a policy recommendation on distributed energy resources and a capacity accreditation policy to be developed by the CMTF later.

SPP Transmission Expansion Planning Report (STEP)
Mr. Lanny Nickell, provided the SPP Transmission Expansion Planning Report (STEP) (SPP Transmission Expansion Planning – Attachment 9). There are several upgrades to the STEP. The Integrated Transmission Planning (ITP), high priority, and balanced portfolio upgrades require board approval. The transmission service, generation interconnection, and sponsored upgrades require board endorsement. In 2015 there were 93 projects completed. There were 50 notifications to construct (NTC) projects. SPP Staff recommends the MOPC endorse a recommendation to the SPP BOD to accept the “2016 SPP Transmission Expansion Plan” report as documentation of completion of the Attachment O transmission planning process.

Seams Update
Mr. Carl Monroe, SPP Staff, provided a Seams Update. MISO has been billed and the first payment should be coming in on February 1st. At the board meeting there will be a presentation on the process and policy of how the revenues will be handled. Market-to-market, between SPP and MISO, has been implemented and although the process is going well, some issues that are being fine-tuned and improved. Mr. Monroe also reported that SPP has had its first international transaction. Saskatchewan Power was able to help in an emergency situation in North Dakota due to a storm that resulted in transmission outages. Saskatchewan Power has a transmission facility that interfaces in North Dakota so they were able to send power and support to that area. That is a milestone for SPP.

Integrated Marketplace Update
Mr. Bruce Rew, SPP Staff, provided an update on the Integrated Marketplace, (Integrated Marketplace Update – Attachment 10). There are 166 market participants with 105 financial only participants and 61 asset owning participants. There are seven new participants since October. The SPP Balancing Authority (BA) has successfully maintained NERC control performance standards. There have been no major winter events to date. The draft wind integration study report confirms the need for additional transmission. The study includes several recommendations. The study has been posted for stakeholder review. The Operations Reliability Working Group (ORWG) will meet in March for more discussion and feedback on the draft report. The results will be presented at the MOPC meeting in April if the report is complete.

Transmission Planning Improvement Task Force (TPITF) Update
Mr. Brian Gedrich, Chair of the TPITF, provided an update on the work of the TPITF, (Transmission Planning
Improvement TF Update – Attachment 11). The TPITF was tasked to look at all of the methodologies and modeling practices used in the studies, the utilization of data to ensure consistency in the planning process, and the appropriateness of the planning cycle and assessments. The recommendations will be presented to MOPC, SPC, and Board in April 2016. Key issues were identified and addressed. The TPITF is looking at going from a three-year to an 18-month planning cycle, using a common planning model, using a holistic planning process, and a standardized scope.

**ACTION ITEMS:**

A list is attached here to. (Action Items – Attachment 12).

**SCHEDULING OF NEXT REGULAR MEETINGS, SPECIAL MEETINGS OR EVENTS:**

- April 25, 2016 – Santa Fe, NM
- July 18, 2016 – Dallas, TX
- October 24, 2016 – Little Rock, AR

At the end of the meeting Commissioner Murphy thanked the SPP Staff for all of their hard work on the new website.

With no further business, the meeting adjourned at 3:53 p.m.

Respectfully Submitted,

Paul Suskie
### Regional State Committee
For the Three Months Ending March 31, 2016
Budget vs. Actual

<table>
<thead>
<tr>
<th></th>
<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Income</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Income</td>
<td>62,964</td>
<td>65,250</td>
<td>(2,286)</td>
</tr>
<tr>
<td><strong>Total Income</strong></td>
<td>62,964</td>
<td>65,250</td>
<td>(2,286)</td>
</tr>
</tbody>
</table>

| **Expense**         |             |            |          |
| Travel/Meeting      | 62,964      | 52,500     | 10,464   |
| Audit               | -           | -          | -        |
| Administrative Costs| -           | 250        | (250)    |
| RSC Consultant      | -           | 12,500     | (12,500) |
| Technical Conference| -           | -          | -        |
| **Total Expense**   | 62,964      | 65,250     | (2,286)  |

| **Net Income**      | -           | -          | -        |
Report to the Regional State Committee
April 25, 2016

Cost Allocation Working Group
(CAWG)
CAWG activities since last RSC/BOD meeting:

• February 9, WebEx/Teleconference
• March 1, AEP Offices, Dallas, TX
• April 5, AEP Offices, Dallas, TX
February 9, WebEx/Teleconference:

• New Member Cost Allocation Process

• Project Tracking Report

• Aggregate Study Waiver Criteria Scope

• Capacity Margin Task Force Update

• 2015 Org Group Survey Results
March 1, AEP Offices, Dallas, TX:

- New Member Cost Allocation Process
- Aggregate Study Waiver Criteria Scope
- Capacity Margin Task Force Update
- CPP Roundtable discussion
April 5, AEP Offices, Dallas, TX:

• Z2 Crediting Process Update
• New Member Cost Allocation Review
• Aggregate Study Waiver Scope
• Capacity Margin Task Force recommendation approved unanimously
• Wind Capacity Accreditation Report
• SPP-MISO settlement and IPSAC update
New Member Cost Allocation Process

• Nebraska CAWG Member John Krajewski will present update
Aggregate Study Waiver Criteria Scope:

• Missouri CAWG Member Adam McKinnie will present update
Capacity Margin Task Force:

The CAWG recommends approval of the policies developed by the CMTF and recommends that they be approved as a package by the RSC. Further, the CAWG believes that the policies are interrelated and should only be considered as a package. It is the CAWG’s position that the proposal provides benefits to ratepayers without jeopardizing reliability.
Z2 Update:

Historical Data Processing (2008 to 2016)

- Historical Calc Pre-Work
- Load Remaining HDP Data
- Gross CPO, BPFO, Sponsor Data, Sch11

Overall SPP FIT

- 6/1 System Readiness – CSS, STT, BPFO, Trans STL
- 5/27 TENTATIVE (can slide w/o impacting HDP GL2)
- 4/25 end – EXTENDED through May
- 5/6 TENTATIVE
- 5/15 TENTATIVE
- 3/31 TENTATIVE

CSS M3 R4 SAT/SIT
BPFO 2/22 end

CSS M3 R2/3 SAT/SIT
1/22 end

Jan Feb Mar Apr May June July Aug Sept Oct Nov
CPP Roundtable Discussion:

• Most states are moving forward with some sort of process/stakeholder input

• Some are doing nothing

• Communicate with your state agency tasked with submitting compliance plan in the event the stay is lifted
SPP-MISO Settlement and IPSAC:

• Stakeholders submitted suggestions for changes to the SPP-MISO Coordinated System Plan (CSP) prior to the December IPSAC meeting

• SPP Staff reviewed the suggestions and presented implementation options & obstacles

• New Seam due to IS Integration into SPP

• March, 25th FERC order accepts, suspends, and rejects
Upcoming CAWG Meetings:

• May 10, 2016 – WebEx/Teleconference
• June 7, AEP Offices, Dallas, TX
• July 7, AEP Offices, Dallas, TX
Questions ?
New Member Cost Allocation Review Process

Prepared by:
COST ALLOCATION WORKING GROUP

RSC REVIEW DRAFT
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1. **HISTORY AND BACKGROUND**

In 2004, the Southwest Power Pool (SPP) was approved as a Regional Transmission Organization (RTO) by the Federal Energy Regulatory Commission (FERC). Since that time, there have been two occasions where SPP experienced a significant expansion of its footprint. Cost allocation for transmission facilities was one issue that was addressed in negotiations between the new members and SPP.

When SPP became an RTO, the Regional State Committee (RSC) was formed and given policy oversight responsibilities for four significant areas. One of these areas was transmission cost allocation. The RSC, working primarily through the Cost Allocation Working Group (CAWG), exercises authority in two specific areas related to transmission cost allocation:

a. whether and to what extent participant funding will be used for transmission enhancements
b. whether license plate or postage stamp rates will be used for the regional access charge

Prior to 2010, facilities were funded under a variety of methodologies, ranging from “MW-Mile” allocation to the “Balanced Portfolio”.\(^1\) In April 2010, the RSC approved the current “Highway/Byway” methodology for new transmission facilities.\(^2\) Under this methodology, any costs for facilities included in the “Base Plan” after June 19, 2010 would be allocated as follows:

1. Less than 100 kV facilities: 100% on a zonal basis
2. 100 to 300 kV facilities: 2/3 to the zone in which the facilities are located, 1/3 on a regional basis
3. Greater than 300 kV: 100% on regional basis

The Integrated System (IS) joined SPP on October 1, 2015. Much of the negotiation involving IS and SPP occurred in 2013 between SPP Staff and IS representatives. During those negotiations, the SPP Staff and IS agreed to propose to the Membership and the RSC a method to include them under the Highway/Byway funding methodology. The intent of the tariff changes was to establish October 1, 2015 as the effective date of cost sharing applicable to SPP members and the IS. The net effect of this change was that the IS zones did not fund SPP facilities with a need date prior to October 1, 2015. Similarly, SPP entities would not fund IS facilities with a need date prior to October 1, 2015.

The other key tariff revision, the Federal Service Exemption (FSE) among other considerations, provided as part of the IS integration, was that the Western Area Power Administration (Western) is not required to pay for regional funding for Federal deliveries to its loads using the IS facilities pursuant to statutory obligations.

During the review of proposed membership of the IS in SPP, several items became clear:

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\(^1\) The Balanced Portfolio methodology involved calculation of benefit/cost ratios and transfer payments to deficient zones.

\(^2\) The Highway/Byway methodology was approved by FERC on June 17, 2010.
1. While the issues under the authority of the RSC are clear, there was not a consensus that certain issues such as the establishment of the effective date for cost sharing of facilities were in fact cost allocation issues.

2. There were no guidelines for what standards should be applied in reviewing issues that were under the RSC’s authority under Section 7.2 of the SPP Bylaws. The lack of standards made it difficult to determine what information was necessary to review the reasonableness of the changes impacting issues under the RSC’s authority.

3. The schedule for the RSC to complete its review was not defined.

As a result of the issues listed above, the RSC and CAWG were unable to reach a consensus on what actions should be taken in spite of a number of unresolved questions, particularly related to the effective date of cost sharing and the appropriateness of the one portion of the FSE. The one motion taken to endorse the new membership proposal at the CAWG failed for lack of a second. The CAWG ultimately voted to take no position on the proposed IS integration. The RSC did not make a motion regarding the membership, though three individual states sent a joint letter on June 6, 2014 to the SPP Board of Members and Members Committee expressing concerns about various aspects of the proposal and the need for further analysis regarding the terms and impacts of the proposed IS membership on existing members and ratepayers within the current SPP footprint. The three states requested that the SPP Board of Directors and Members Committee delay their decision to no sooner than the regular July 2014 Board meeting. The state of Kansas intervened in the FERC proceeding opposing the change in the effective date of cost sharing, the FSE, along with other issues. The state of Texas also intervened in the FERC proceeding and submitted comments to state that it did not support the proposed revisions to SPP’s governing documents due to concerns regarding the cost-benefit analysis and the FSE, among other issues.

The RSC discussed the communication and process issues related to new member review over the course of several meetings in early 2015. In April 2015, the RSC directed the CAWG to develop a cost allocation review process that could be used in future discussions involving new members. The CAWG drafted a scope of the issues that would be included in the review process and a schedule for completion. That scope (included as Attachment A) was approved by the RSC at the July 27, 2015 meeting.

This document is designed to provide a process for the RSC and CAWG to follow in the future when a potential new member is being considered, particularly when that new member is asking for significant changes to the SPP Open Access Transmission Tariff (OATT) or Membership Agreement that would impact the RSC approved regional cost allocation. This process is intended to work as a separate, parallel process with the communication and work group processes delineated in the New Member Task Force report that was approved by the RSC at the July 27, 2015 meeting and subsequently approved by the SPP Board of Directors (see Attachment B). It is anticipated that information will be shared between SPP Staff, the RSC and CAWG to ensure timely completion of the review process contemplated in this document. Sharing of information would be subject to the resolution of any issues pertaining to confidentiality.
2. PURPOSE / GOAL STATEMENT

The purpose of this document is to provide the RSC and CAWG a process to follow when considering cost allocation issues related to potential new transmission-owning member additions to the SPP. This review process is particularly important when the new member is requesting modifications to SPP’s governing documents (OATT, Bylaws, Membership Agreement) that go beyond pro forma changes and would impact the authority of the RSC pursuant to Section 7.2 of the SPP Bylaws.

2.1 GOAL STATEMENT

The goals of the New Member Cost Allocation Review Process (Review Process) is to evaluate the impact of new transmission owning members on stakeholders (including retail ratepayers) in the existing SPP footprint and assess the benefits that would accrue to existing stakeholders. The impact assessment is intended to take into account economic and non-economic impacts. In addition, this process is intended to assist the RSC in developing a position regarding cost allocation issues for new members as well as an action plan, consistent with the RSC’s authority under Section 7.2 of the SPP Bylaws.

While it is the role of FERC to make the determination as to whether a proposed cost allocation methodology results in rates that are just and reasonable, the RSC may intervene in such cases or file its own alternative cost allocation methodology, which may be in conflict with the methodology filed by SPP staff. The RSC positions developed as a result of this document may be used to determine whether to intervene in FERC proceedings or file an alternative cost allocation methodology.

3. OVERVIEW OF PROCESS

The Review Process will consist of several steps, which will be completed over a prescribed time period as outlined in Section 8.1. The process generally includes the following steps:

1. Collect information about proposed new member (Section 4).
2. Review previous cost allocation and integration approaches, for purpose of determining reasonableness of proposed approach for the new member being considered (Section 5).
3. Complete analyses (Section 6).
4. Discuss other considerations (Section 7).
5. Prepare recommendation for RSC action.

4. NEW MEMBER CHARACTERISTICS

SPP Staff shall provide all available information to the RSC and CAWG about the new member as set forth in the SPP Stakeholder Communication Process, for purposes of completing the Review Process. Certain information may be confidential or unavailable. In addition, the information listed as follows may be Critical Energy Infrastructure Information (CEII) and as such
would need to be afforded the appropriate protections. The information to be collected by SPP and provided to the RSC/CAWG is as follows:

4.1 TRANSMISSION FACILITIES AND PLANNING INFORMATION

Related to transmission facilities owned by the potential new member:

1. Line miles of transmission owned, separated by voltage class
2. List of existing interconnection points to SPP
3. List of interconnection points to neighboring RTO regions
4. List of utilities in non-RTO regions that new member is interconnected with, along with interconnection points
5. Transmission planning studies used to determine if existing facilities are adequate to meet SPP Planning Criteria and applicable NERC TPL standards (steady state, dynamics and short circuit) in effect when the evaluation is being prepared
6. Current cost recovery mechanism for transmission service (i.e., Stand-alone FERC-jurisdictional Open Access Transmission Tariff, joint tariff with other transmission owners, membership in Regional Transmission Organization, non-jurisdictional transmission tariff)

4.2 GENERATION AND LOAD INFORMATION

Related to the potential new member:

1. Actual summer and winter peak demand (including capacity sales) for most recently completed calendar year. (Note: May be provided for alternate 12-month time period based on information availability.)
2. Comparison of peak demand to capacity resources by month for most recent year, including calculation of reserve margin.
3. Projected peak demand for 10-year period, beginning in current year.
4. Comparison of projected peak demand to resources for subsequent 10-year period.
5. For planned resources, identify location and status of transmission planning to integrate resources into transmission system.
6. Resource mix, including fuel type.

4.3 MODIFICATION TO SPP GOVERNING DOCUMENTS

SPP Staff shall provide, as developed in the SPP stakeholder process (see Attachment B), in clean and redline format, all proposed changes to the following documents related to the new member that impact areas under the authority of the RSC pursuant to Section 7.2 of the SPP Bylaws:

1. Open Access Transmission Tariff
2. Membership Agreement
3. SPP Bylaws
4. Regional State Committee Bylaws
5. SPP Criteria

SPP Staff shall provide a summary of those changes that go beyond “pro forma” changes and provide information related to any changes that affect cost allocation and other areas under the authority of the RSC pursuant to Section 7.2 of the SPP Bylaws. SPP Staff shall identify and provide the purpose for any changes that impact areas under the authority of the RSC pursuant to Section 7.2 of the SPP Bylaws beyond pro forma changes. The RSC and CAWG can review and ensure that the proposed changes are consistent with the Goals listed in Section 2.1.

For purposes of this document, a “pro forma” change to a governing document (Tariff, Bylaws, Membership Agreement, and Service Agreement) is defined as, but not limited to, one of the following examples:

1. Addition of new member to list of signatories.
2. Addition of new members taking service under the pro forma Tariff. Examples include Attachment H (addition of a new member’s stated rate or Formula Rate Template to Revenue Requirements calculations) or Attachment M (a new member’s Transmission loss factors).
3. Effective date of integration for new member, unless establishment of the effective date results in other substantial revisions to the Tariff.
4. Creation of a new zone for a new member, or adding a new member to existing zone, provided no other cost allocation changes are being proposed.

5. PREVIOUS COST ALLOCATION AND INTEGRATION APPROACHES

The purpose of this section is to provide the RSC and CAWG examples of how new member integration has occurred in the past within SPP as well as in other RTOs. These examples are intended to provide a “range” of reasonable cost allocation approaches that have been used previously and approved by FERC so the RSC and CAWG can determine if the new member integration is being treated in a fashion similar to previous situations. However, approaches that differ from an approach previously used will be evaluated on their own merits to determine if is just and reasonable. If a new member is offered terms that differ substantially from those that have been offered in previous new member integration cases, then the RSC and CAWG may want to complete further investigation into the reasonableness of the proposed changes.

Because of the volume of information and the potential for additional data in the future, this information is included as a separate Appendix 4.

6. CRITERIA FOR COST ALLOCATION REVIEW

6.1 RATE STANDARD
The SPP OATT is governed by FERC and is required to meet the “just and reasonable” rate standard. As such, any tariff changes related to the addition of a new member must meet this rate standard. As the RSC develops a position regarding the areas under its authority pursuant to Section 7.2 of the SPP Bylaws, it should keep in mind the rate standards that FERC will apply in its review.

6.2 IMPACT TO EXISTING MEMBERS

In the past, SPP evaluated the impact on existing members using two primary metrics: ATRR and SPP Schedule 1-A (Administration Charge). The costs for these two components were evaluated to determine if there would be a cost or savings. In the case of the IS integration, each existing transmission zone had a net benefit when ATRR and Administration Charge were considered.

The CAWG will evaluate the effect of new members on the existing SPP region. Any proposed integration that results in a cost/benefit to the existing SPP customer base of less than 1.0 may warrant further consideration by the RSC.

6.3 EVALUATION METHODOLOGY

6.3.1 ADMINISTRATION CHARGE

SPP will calculate the projected change in the Administration Charge (Schedule 1-A) with the new member integration. The revised Schedule 1-A costs will take into account projected load changes as well as projected incremental costs, if any, associated with serving new members. The change in Administration Charge shall be tabulated for the existing SPP footprint and for each existing transmission zone.

6.3.2 TRANSMISSION COSTS

SPP will calculate the existing (without new members) and projected ATRR for each transmission zone and for the existing SPP footprint as a whole. The calculations will take into account already-issued Notices to Construct (NTCs) for the existing footprint and facilities planned by the potential new member that are expected to receive base plan funding.

6.3.3 PRODUCTION COSTS

For purposes of new member integration benefit/cost analysis, adjusted production cost benefits may be considered in certain circumstances. In general, production cost analysis will not be included unless one of the following conditions is expected:

1. The new member has significantly different generation profile than the existing footprint.
2. Integration of the new member is expected to result in significant changes in locational marginal prices or congestion in the existing SPP footprint.

### 6.3.4 OVERALL BENEFIT / COST EVALUATION

The following parameters shall be used to determine the benefit/cost ratio of the new member on existing members:

1. The economic parameters most recently approved for use by the Economic Studies Working Group shall be used. These parameters may be associated with a recently completed study or a study that is in process.
2. A 40-year study horizon shall be used.
3. Only costs and benefits associated with the Administration Charge (Schedule 1-A) and ATRR shall be considered, unless CAWG determines that it is appropriate to model adjusted production costs.
4. Other benefits, such as reserve sharing costs, market related benefits or transmission planning synergies, may be considered on a case by case basis.

The net benefits/costs shall be calculated for SPP as a whole and for each existing transmission zone if possible. Benefits and costs related to the Administration Charge, ATRR, production (if applicable and if possible), and other benefits as determined will be provided by SPP Staff if available as specified in the SPP Stakeholder Communication Process (Attachment B).

### 6.3.5 NON-ECONOMIC / QUALITATIVE BENEFITS

If there are other non-economic or qualitative benefits that would accrue to existing SPP stakeholders, SPP staff will identify those benefits and provide information to the RSC regarding those benefits. Non-economic or qualitative benefits may be taken into account in the evaluation, but will not be considered as an offset against costs to existing stakeholders. In situations where economic benefits to existing stakeholders associated with a new member are minimal, non-economic or qualitative benefits may be considered by the RSC in developing a position regarding cost allocation issues associated with the new member.

### 6.4 EFFECTIVE DATE FOR HIGHWAY/BYWAY COST-SHARING

Among the considerations that may inform the analyses on the reasonableness of the cost sharing are the following:

1. Should the effective date of cost sharing be tied to the need date for SPP projects and the projects of a new member? The various approaches to cost sharing may include but are not limited to the following:
a. *Need Date Approach:*

i. Upgrades in the existing SPP system and those in the new member system that have a need date prior to a certain date (e.g. integration date) are not subject to cost sharing;

ii. Upgrades in the existing SPP system and those in the new member system that have a need date after a certain date (e.g. integration date) are subject to cost sharing. The analysis may consider whether the only evaluation required for projects of a new member is a need-by-date analysis or whether such projects must be evaluated in an SPP regional planning process or a high priority planning process before they can be subject to cost sharing.

b. *Combination of Need Date and RCAR Approach:* In addition to the need date approach, the benefits derived by the new member from the use of SPP highway/byway facilities in place before the cost sharing date and, if applicable and possible, the benefits derived by SPP from the use of existing upgrades of the new members would be evaluated in a future RCAR approach.

c. *Delay and/or Transition Period for Cost Sharing Approach:* Factors that may be considered are:

i. a need for a pre-determined transition period after the integration date during which cost sharing for existing upgrades or new projects does not occur or occurs to a limited extent;

ii. the cost sharing for existing upgrades is phased in over a period of time according to a pre-determined methodology and the cost sharing for projects with a need date after the effective date of integration is applied only to transmission projects that have been evaluated and studied in an SPP regional planning process (e.g. ITP process or a high priority study as delineated in SPP tariffs).

d. *Cost Sharing for All Applicable Projects Regardless of Need Date and Effective Date of Membership:* There is no distinction made between projects based on need date for projects with respect to cost sharing.

i. Cost Sharing for Existing Upgrades: A new member and SPP will share in the unrecovered costs of each other’s existing upgrades (100 kV and above). The analysis may limit the scope of the upgrades to which such cost sharing may apply to the extent there are any complexities involved in implementing this approach.

ii. Cost Sharing for New Upgrades: The costs of projects 100 kV and above that are approved for construction by the SPP Board and by the
relevant board of a new member will be shared by SPP and the new member. The analysis may consider whether the only evaluation required for projects approved by the relevant board of a new member is a need-by date analysis or whether such projects must be evaluated in an SPP regional planning process or a high priority planning process before they can be subject to cost sharing.

2. Should the impact of the integration date on SPP stakeholders (including the existing retail rate-payers in the SPP footprint) or the new member as it relates to cost sharing be considered?

The analysis may consider if, with respect to cost sharing, the date on which a new member seeks to integrate into the SPP system adversely impacts SPP stakeholders or the new member. As an example, SPP or the new member may approve projects as a result of federal regulations and policy directives (e.g. Clean Power Plan). These projects may entail significant investment and have need dates prior to the effective date of integration of the new member into SPP. If establishment of an effective date for cost-sharing results in disproportionate benefits to either the new member or the existing SPP stakeholders, a change in cost allocation methodology may be warranted. Under certain cost sharing approaches (e.g. need date approach), described above, the new member and SPP will not be responsible for cost sharing for such SPP or new member projects.

6.5 FACILITIES AND ENTITIES TO WHICH COST-SHARING APPLIES

The analysis should consider the following aspects of facilities to which cost sharing may apply:

1. Voltage of transmission lines
2. Classification of upgrades, if applicable: Reliability, Economic, and Public Policy

6.6 OTHER CONSIDERATIONS

There may be other relevant considerations in an analysis regarding cost sharing.

6.6.1 MINIMIZING ADMINISTRATIVE BURDEN ON SPP

One of the goals of a cost sharing approach adopted in the context of new member integration should be to maintain consistency/uniformity in tariff rates and minimize the administrative burden on SPP, its members, and the new member to the extent possible without compromising on the goals outlined in section 2.1 of this document. For example, there should be an effort to avoid creating new schedules that reflect different region wide rates for new members.

6.6.2 CONSIDERATION OF SPECIAL CIRCUMSTANCES
To the extent there are special circumstances that need to be considered in the evaluation of cost sharing for new members such as exemptions for certain new members (e.g. exemption due to federal statutory requirements or grandfathered agreements), SPP Staff should provide information on the following in a manner consistent with the Proposed SPP Stakeholder Communication Process:

1. Scope of the exemption
2. Legal analysis demonstrating that such exemption is warranted, if applicable
3. Technical evidence demonstrating that the new member seeking exemption will not benefit from upgrades in the SPP system after integration
4. Documents supporting the basis for such exemption, if applicable

### 6.6.3 USE OF THIRD-PARTY VS. SPP ANALYSES

Each prospective new transmission-owning member may have unique characteristics associated with its transmission system. SPP Staff shall provide the following information in a manner consistent with Proposed SPP Stakeholder Communication Process:

1. A cost/benefit analysis to determine the impact the addition of the prospective transmission-owning member’s system would have on existing SPP members
2. A more extensive production cost/benefit analysis conducted by SPP Staff or by a third party under SPP direction, if requested by the SPC or the RSC.
3. To the extent SPP relies on cost/benefit analysis or a study performed by the new member, detailed information of such studies to permit review of such studies (to the extent it is available and not protected by confidentiality provisions).

### 7. FACTORS WHICH MAY RESULT IN DEVIATION FROM APPROVED COST ALLOCATION CRITERIA

This is not an exhaustive list of circumstances that may warrant a deviation from following these criteria or strictly adhering to this process. Any and all requests for deviation shall follow Section 6 – Criteria for Cost Allocation Review in addition to the considerations or factors noted in this section.

#### 7.1 REMOTE SYSTEM WITHOUT AC INTERCONNECTION

Should a new member request joining SPP without having any direct AC interconnection to the SPP system, several factors will need to be considered. First and foremost is what transmission path, or paths, is available for connection to the SPP system should energy be dispatched to or from the new member system. This may prove difficult to determine and
independently verify as the pathways are outside of the SPP footprint and management. It shall be the responsibility of the new member to identify these pathways and determine what costs are associated with delivering energy to and from the SPP system to the requesting member’s system, including any congestion and their associated costs which may arise from moving energy across non-SPP systems. Second, the new member shall provide a cost/benefit analysis for each and every identified pathway and a methodology for mitigation and independent verification should the non-SPP system owner determine that energy moved across pathways not identified by SPP or the new member. Lastly, once the pathways for interconnection are identified, the new member shall propose what form of agreement be in place to effectuate efficient and cost effective transmission of energy over non-SPP member systems including proposed time frames for such agreements, and proposed exit payment provisions should these agreements not be renewed.

Should the new member request that their system remain as a stand-alone system, the preferred methodology for cost allocation for the new member will be that all transmission cost for the new member’s system be directly assigned to that new member. Any request for an alternate cost allocation methodology under this scenario shall be accompanied by a cost/benefit analysis.

7.2 SYSTEM WITH LIMITED INTERCONNECTION CAPABILITY

Should a new member request to join SPP having only limited interconnection to the SPP system, the following factors will need to be considered. For pathways on the new member’s system with limited interconnection capability the new member shall clearly identify the nature of those limitations including both qualitative and quantitative analysis of the limitations noting any time based limitations. Additionally, the new member shall identify what alternate transmission path or paths are available for connection to the SPP system should energy be dispatched to or from the requesting member and the interconnection limitations force energy to travel along alternate paths on non-SPP systems. It shall be the responsibility of the new member to identify these pathways and determine what costs are associated with delivering energy to and from the SPP system to the requesting member’s system, including any congestion and their associated costs which may arise from moving energy across non-SPP systems. The new member shall provide a cost/benefit analysis for each and every identified pathway and a methodology for mitigation and independent verification should the non-SPP system owner determine that energy moved across pathways not identified by SPP or the new member. Again, this may prove difficult to determine and independently verify as the pathways may lie outside of the SPP footprint and management. It shall be the responsibility of the new member to identify these pathways and determine what costs are associated with delivering energy to and from the SPP system to the requesting member’s system, including any congestion which may arise from moving across non-SPP systems.

7.3 SYSTEM EMBEDDED IN EXISTING SPP MEMBER

There are a number of entities that are not members of SPP embedded within existing transmission owners. It is possible at some point in the future they may seek membership in SPP, either as a transmission owner or as a transmission user. One example of this type
of entity would be a municipal system with transmission interconnections to a single transmission system. Another example would be a cooperative system that is a member of a cooperative that is already an SPP member that is seeking its own separate membership.

To the extent these entities do not seek changes beyond pro forma changes to SPP’s governing documents, the necessary review under this document would be unnecessary. If the embedded entity is seeking changes to cost allocation methodology, effective date of cost-sharing for new facilities, or any other changes to SPP’s governing documents, the provisions of this document would apply.

There have been instances where a new member is requesting to have its loads and transmission facilities included in the zone of an existing transmission zone. SPP Staff reviews such requests in a manner consistent with the tariff and the requirement that rates meet the just and reasonable standard established by FERC. If no other changes to cost allocation are being requested by the new member, the CAWG will not complete a review of the new member using this document.

### 7.4 SYSTEM WITH REQUIREMENTS TO SERVE UNDER FEDERAL LAW OR PRE-EXISTING CONTRACTS

There may be situations where a new member has a statutory prohibition from participating in the existing cost allocation methodology. This occurred in the case of the IS membership through the application of the FSE. Exempting future members from SPP’s transmission allocation methodology will be reviewed on a case-by-case basis by the CAWG. The CAWG will consider the following factors in determining the acceptability of any potential exemptions or deviations from cost allocation methodology in a manner consistent with the Proposed SPP Stakeholder Communication Process:

1. Legal review of the requested cost allocation approach
2. Cost / benefit review of requested cost allocation approach
3. Impact on existing members and proposed members
4. Precedent established for future membership applications

### 8. REVIEW PROCEDURES

The following review procedures shall be followed to ensure timely review of cost allocation issues related to potential new transmission-owning member additions to the Southwest Power Pool.

#### 8.1 SCHEDULE

The following schedule shall be followed after the SPC’s new member forum discusses the proposed new member. All dates referenced are relative to the date when all necessary information is provided by SPP staff:

- 30 days: CAWG shall meet to discuss information and analyses.
• 60 days: CAWG shall provide a report to the RSC, including the CAWG’s recommended course of action.

Next scheduled RSC meeting following receipt of the CAWG report: RSC shall discuss the report findings and vote on action to be taken. Note: If the proposed integration has shorter timeframe, a special RSC meeting may be necessary.

8.2 REPORT OF FINDINGS TO RSC

The CAWG shall provide a report to the RSC that includes, but is not limited to, the following information:

1. Proposed New Member Information
   a. Transmission Facilities and Planning Information (Section 4.1)
   b. Generation and Load Information (Section 4.2)
   c. Proposed Modifications to SPP Governing Documents (Section 4.3)

2. Cost Allocation Review
   a. Rate Standard (Section 6.1)
   b. Impact to Existing Members (Section 6.2)
   c. Evaluation of Costs and Cost Benefit Analysis (Section 6.3)
   d. Effective Date for Cost-Sharing (Section 6.4)
   e. Facilities and Entities to Which Cost-Sharing Applies (Section 6.5)
   f. Other Considerations (Section 6.6)

3. Recommendation to RSC, including Action Plan

8.3 ACTION PLAN

The report shall include a recommended course of action that may include, but is not limited to:

1. Endorsement of the proposed member(s);
2. No action taken; or
3. Oppose the integration of the proposed new member(s) through FERC proceedings. Opposition may or may not include filing of alternate cost allocation methodology (Section 205 filing).
ATTACHMENT A: NEW MEMBER REVIEW PROCESS SCOPE

Approved by RSC, July 27, 2015
New Member Cost Allocation Review Process Scope Document

1. Identify new member characteristics
   a. Transmission Facilities
   b. Generation and Load Characteristics
   c. Proposed modifications beyond pro forma changes to the Tariff and other governing documents

2. Identify cost allocation and integration approaches used in other similar situations
   a. Existing SPP integration – Nebraska and Integrated System
   b. Other RTO member additions
   c. Non RTO member additions

3. Develop criteria used to analyze the application of existing cost allocation methodologies for future new members
   a. Rate standard
      i. Public interest
      ii. Just and reasonable
   b. Impact to existing members and new members
   c. Evaluation methodology
      i. Administrative costs
      ii. Production costs
      iii. Transmission costs
      iv. Appropriate benefit / cost measurements
      v. Ensure coordination with SPP
   d. Appropriate effective date for cost-sharing
   e. Appropriate facilities and entities to which cost-sharing to be applied
   f. Practical considerations for implementing cost-sharing

4. Identify other factors that may warrant deviation from established cost allocation criteria
   a. Remote system without direct AC interconnections
   b. System with limited interconnection capability to SPP region
   c. Systems embedded within SPP member transmission system

5. Draft procedures for CAWG/RSC use in future reviews
   a. Schedule for completion
   b. Reporting findings
   c. Action plan

6. Other considerations
   a. Need for uniformity in tariff language relating to cost-sharing
   b. Minimizing administrative burden on SPP
   c. Phasing in or delaying of cost allocation for new members
   d. Consideration of special circumstances (ex. Federal Service Exemption)
   e. Ensure that a Goal Statement is included in the final draft of the scope document
f. Use of third-party technical and/or economic analysis in addition to SPP internal technical and/or economic analysis

7. Other Issues of Interest to the RSC

Schedule for Completion

1. Approval of scope for July 2015 RSC meeting
2. Review scope items 1, 2, and 3 – October 2015
3. RSC approval of CAWG review procedures – January 2016
ATTACHMENT B: SPP TASK FORCE ON NEW MEMBERS PROPOSED
SPP STAKEHOLDER COMMUNICATIONS PROCESS

Approved by SPP Board of Directors, July 2015.
Introduction

Given communication concerns raised during the Integrated Systems addition to the Southwest Power Pool (SPP) in 2013/2014, the SPP Board charged the Strategic Planning Committee to develop improved and enhanced communications and processes for new member additions to SPP. At the July 17, 2014 SPP Strategic Planning Committee (SPC) meeting, the SPC Task Force on New Members (SPCTFNM) was formed and charged with developing recommended prospective communication and work group processes that would be followed during the various stages of engaging prospective transmission-owning and load serving members. The outcome of this Final Report and Communication Process only applies to prospective transmission-owning members who request membership contingent upon modifications beyond minor pro forma changes to typical new members to the SPP Open Access Transmission Tariff (OATT), Governing Documents, or Regional State Committee (RSC) Bylaws.3

The SPCTFNM had several meetings over the course of fall of 2014 and reviewed the existing SPP Staff process document for adding prospective transmission-owning members and discussed improvements in the SPP Staff process as well as documenting a recommended Communication Process for future transmission-owning member additions. The SPCTFNM was guided by the overarching need to allow flexibility to deal with unique features of the prospective transmission-owning member throughout the process, while balancing appropriate transparency for member participation while allowing for confidential discussions/negotiations. Noteworthy is that the SPP staff remains solely responsible for the direct negotiations with the prospective member with input from the stakeholders on both policy and specific changes to the governing documents.

When evaluating the overall process of adding new transmission-owning members, the prospective member goes through the following five stages:

1. Initial Discussions
2. Due Diligence and Membership Agreement Discussions
3. SPP OATT and Governing Document Changes
4. FERC Approvals
5. Integration

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3 The applicability of the process contained herein is further defined in Chart 1, Applicability of New Member Process, contained on Page 6.
Each of these stages will be discussed further in this Final Report and the recommended Communication Process improvements are noted for each of the stages. The focus of the SPCTFNM efforts was on Stages 1, 2 and 3 as those are the stages where most communications and discussions are confidential and proprietary to the SPP region and where the communication concerns were concentrated.

Regarding the effective date for regional cost sharing associated with the integration of the new member, the SPCTFNM brought the issue to the RSC to determine how the issue should be addressed. The SPCTFNM recommends that while the issue is a significant concern when adding a new transmission-owning member to the SPP region, the issue is outside the scope of this task force which was tasked with improving the communication process.

This document is the final product of the SPCTFNM and recommends the Strategic Planning Committee (SPC) approve the recommendations for process improvements. SPP Staff has also made a series of changes and clarifications in the Staff work process document, which is included in this report as ATTACHMENT A.

**Key Definitions**

Stakeholders – Stakeholders include existing transmission-owning members, transmission-using members, and RSC members and their staffs.

Prospective transmission-owning member – A potential SPP member who is seeking to bring its transmission system into the SPP region. Due to its request for membership, the prospective member requires modifications to the SPP OATT (beyond minor pro forma changes for typical new members), Governing Documents, or RSC Bylaws.

Members Forum – A group of interested SPP members, including SPP members who are electrically adjacent to the prospective transmission-owning member, who will give guidance to SPP Staff. A prerequisite to joining the Members Forum is an executed SPP Members Agreement and confidentiality agreement.

State Commission Forum – A group of interested RSC Commissioners or Commission Staff who will give guidance to SPP Staff. A prerequisite to joining the State Commission Forum is an executed confidentiality agreement.

Governing Documents – Includes the SPP Bylaws and SPP Membership Agreement.

First Triggering Event – Typically when the potential new transmission-owning member formally requests SPP to begin negotiations to change the SPP OATT, Governing Documents, or RSC Bylaws to allow for its membership into SPP.

Second Triggering Event – This occurs when SPP Staff and the prospective transmission-owning member determine that the discussions and the potential new member information need to become public to all SPP Stakeholders.
Communication Process

Stage 1: Initial Discussions
Periodically, prospective transmission-owning members approach SPP, typically in confidence, indicating they would like to discuss membership. SPP Staff will periodically report to the SPP SPC the general discussions and these discussions may remain “general” for months and years. SPP Staff does not take any formal action until the First Triggering Event occurs, which is typically when the prospective new transmission-owning member formally requests SPP to begin negotiations to change the SPP OATT, Governing Documents, or RSC Bylaws to allow for its membership into SPP.

Once this First Triggering Event occurs, SPP Staff formally notifies the SPC. If the potential new member requests confidentiality of the negotiations, or if the new member is also negotiating with another Regional Transmission Organization (RTO), the negotiations are considered proprietary, and updates to the SPC are conducted in Executive Session with proper notification given, by ensuring the meeting agendas note an Executive Session is expected and the topic is New Members. In the Executive Session, the phones may be closed out; however, all SPP Members and RSC Commissioners or Commissioner Staff present at the meeting shall be permitted to remain in the Executive Session.4

Once this First Triggering Event occurs, SPP Staff also shall establish a Members Forum and State Commission Forum to give guidance and assist SPP Staff on due diligence. The Members Forum is typically open to SPP members who are located electrically adjacent to the potential new transmission-owning member(s) and while no existing Member requesting to join the Members Forum is turned down, the Members Forum size needs to be managed so that SPP Staff can be agile and efficient in their work.

All SPP members, as well as RSC and commission staff, may attend the SPC Executive Session discussions on New Members. For these Executive Sessions, an executed confidentiality agreement will be required for all participants.

Stage 2: Due Diligence and Membership Agreement Discussions
During this stage, SPP Staff is solely responsible for the negotiations with the prospective new transmission-owning member. The SPP SPC, State Commission Forum and Members Forum can provide input to SPP Staff as well as receive regular updates on progress or issues of concern. These discussions, and updates from the due diligence work SPP Staff conducts, are typically highly confidential and proprietary. Also during this stage, SPP Staff provides regular updates to the SPC and as the updates require, in Executive Session. The Executive Session will be noticed on the agenda. As appropriate, SPP Staff will provide updates to the appropriate working groups and committees, including the SPP Board, Members Committee, RSC, and Markets and Operations Policy Committee (MOPC).

During this stage, a Second Triggering Event occurs that makes the discussions and the potential new member’s identity public to all SPP Stakeholders. Once this Second Triggering

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4 Subject to assurances from Commissioners and Commission staff regarding protection of confidential information that may be subject to Freedom of Information Act and state open meeting laws.
Event occurs, SPP Staff convenes a special all-member meeting to discuss all the proposed
document changes and analyses conducted to date.

Each prospective new transmission-owning member generally has unique characteristics
associated with its transmission system. In all cases, SPP Staff conducts a cost/benefit
analysis to determine the impact the addition of the prospective transmission-owning
member’s system would have on existing SPP members. The potential new transmission-
owning member may conduct a cost/benefit study of its own that could include a production
cost analysis.

The SPC shall make a determination of whether to have a more extensive production
cost/benefit analysis conducted, either by SPP Staff or by a third party under SPP direction.
When posting the SPC agenda, SPP Staff will ensure the agenda states there is a new member
discussion item and that it may be discussed in Executive Session. The decisions to conduct
such a cost/benefit study will be evaluated on a case-by-case basis.

**Stage 3: SPP OATT and Governing Document Changes**

During this stage, SPP Staff is solely responsible for the direct negotiations with the
prospective new member, and the SPP SPC, State Commission Forum and Members Forum
provide input to SPP Staff as well as receive regular updates on progress or issues of concern.
During this stage, SPP Staff provides regular updates to the SPC and as the updates require,
in Executive Session. As appropriate, SPP Staff will provide updates to the appropriate
working groups and committees, including the SPP Board and Members Committee, RSC,
and MOPC.

At this stage, SPP Staff convenes a special all-Member meeting to discuss the proposed OATT
and Governing Document Changes and any analyses conducted to date. Throughout this
stage, as appropriate, SPP Staff shall provide updates to the appropriate Working Groups and
Committees, including the SPP Board and Members Committee, the RSC, the Cost Allocation
Working Group, and MOPC.

When SPP Staff convenes the special all-Member meeting SPP Staff shall include the RSC
Commissioners and Commission staff. The RSC may request SPP Staff to hold a special
meeting of the RSC to review the proposed changes; however, this would not preclude the
RSC Commissioners or Commission Staff from attending the all-Member special meeting to
review and discuss the potential document changes and new members.

Finally, if the SPP OATT and Governing Documents are amended and presented for
stakeholder approval, the following groups’ roles are defined.

**MOPC:** Prior to going to the Members Committee and Board for a vote, any changes
to the SPP OATT will be presented to MOPC for all members to discuss and vote on
changes.
SPC: Prior to going to the Members Committee and Board for a vote, all negotiating strategies, guidance, and deliberations for prospective new members will be reviewed by the SPC, either in an open meeting or Executive Session for review and approval.

Corporate Governance Committee (CGC): Prior to going to the Members Committee and Board for a vote, any changes to the Governing Documents will be reviewed and approved by the CGC.

RSC: SPP Staff will provide regular updates to the RSC on new transmission owning member deliberations and negotiations. Any matters for which the RSC has delegated authority will be presented to the RSC for discussion and approvals, in accordance with the RSC and SPP Governing Documents, prior to SPP Board action.

**Legal Analysis**

Depending on the unique characteristics of the potential new member, or the request of the potential new member for OATT and Governing Document changes, a legal analysis may be required. The prospective new member shall be responsible for any legal analysis it needs. SPP will be responsible for any legal analysis SPP determines it needs. Any time the potential new member indicates that it has identified a matter for which it is seeking a legal analysis, an analysis may be requested of SPP’s General Counsel. This request should be made in writing.

Additionally, on a case-by-case basis, Stakeholders, as defined in this document, may request an SPP legal analysis on issues related to the prospective new member. This request should be made of the General Counsel in writing. Nothing in this recommendation precludes any SPP Member, the RSC, or State Commission from pursuing its own legal analysis on any legal matter associated with the prospective new member.

The SPP General Counsel has a process for conducting general legal analyses in response to such requests. This process documents how that legal analyses would be pursued and disseminated during the non-public and public stages of the process of adding new members. Such legal analysis would be released subject to the resolution of attorney-client privilege issues and professional responsibility obligations.
# CHART 1

## Applicability of New Member Processes

Below are examples of situations of when the New Member Process Document will and will not apply to prospective new members integrations into SPP.

<table>
<thead>
<tr>
<th>New Member Process Document Applies</th>
<th>New Member Process Document Does Not Apply</th>
</tr>
</thead>
<tbody>
<tr>
<td>The prospective New Member is requesting changes to the SPP tariff including Schedule 11, Schedule 12, Attachment J, Attachment AE, or other rate schedule.</td>
<td>The prospective New Member is only requesting pro forma changes to the SPP tariff.</td>
</tr>
<tr>
<td>The prospective New Member is requesting significant changes to the pro forma SPP Membership Agreement.</td>
<td>The prospective New Member is only requesting minor changes to their membership agreement or changes to the membership agreement already approved by FERC for other members of the same zone.</td>
</tr>
<tr>
<td>The prospective New Member is requesting significant changes to the SPP Bylaws.</td>
<td>The prospective New Member has no requested changes to the SPP Bylaws.</td>
</tr>
<tr>
<td>The prospective New Member is requesting significant changes to the RSC Bylaws or to the delegated authorities of the RSC, as stated in the SPP Bylaws.</td>
<td>The prospective new member is not a prospective transmission-owning member.</td>
</tr>
<tr>
<td>Any other instances not specifically listed herein where the SPC or Board of Directors determine that the changes are significant enough that the New Member Process Document should apply.</td>
<td>The prospective new member will not be classified as a TO member within the SPP Membership Agreement.</td>
</tr>
<tr>
<td>Any other instances not specifically listed herein that are within the responsibilities of the RSC, where the RSC finds that the changes are significant enough that the New Member Process Document should apply.</td>
<td></td>
</tr>
</tbody>
</table>


APPENDIX 1: DESCRIPTION OF NEBRASKA MEMBERS

- Omaha Public Power District (OPPD) - OPPD has been operating since 1946 and is a publicly owned, business-managed electric utility governed by an elected board of eight directors. OPPD is headquartered in Omaha, Neb.; with other locations in a 13-county, 5,000-square-mile service area. OPPD serves a population of approximately 799,000 people, more than any other electric utility in the state and ranks as the 12th-largest public power utility in the U.S. in number of customers served. OPPD serves 47 towns at retail and five at wholesale. The majority of OPPD's power comes from three baseload power plants: North Omaha Station and Nebraska City Station, both coal-fired plants, and Fort Calhoun Station, a nuclear power plant. OPPD has generating capability of 3,232 MW and a system peak load of 2,291 MW.

- Lincoln Electric System (LES) - Feb. 1, 1966, Lincoln Electric System was formed and a single utility began providing electric energy in and around Lincoln, Neb. In November 1970, Lincoln voters approved formation of a semi-autonomous administrative board of local citizens to oversee operations of the nonprofit, customer-owned utility. Today, LES services approximately 200 square miles within Lancaster County in Nebraska, comprising the cities of Lincoln, Prairie Home, Waverly, Walton, Cheney, and Emerald. The primary goal of their approximately 500 employees is to provide an adequate and reliable electric supply at the lowest possible cost to its more than 116,000 residential customers and 15,000 commercial and industrial customers.

- Nebraska Public Power District (NPPD) - NPPD is Nebraska’s largest electric utility, with a chartered territory including all or parts of 86 of Nebraska’s 93 counties. NPPD was formed on Jan. 1, 1970, when Consumers Public Power District, Platte Valley Public Power and Irrigation District (PVPPID) and Nebraska Public Power System merged to become NPPD. Merger properties also included assets formerly operated by Loup River Public Power District. NPPD is a public corporation and political subdivision of the state of Nebraska. The utility is governed by an 11-member Board of Directors, who are popularly elected from NPPD’s chartered territory. NPPD’s revenue is mainly derived from wholesale power supply agreements with 50 towns and 25 rural public power districts and rural cooperatives that rely totally or partially on NPPD’s electrical system. NPPD also serves about 80 communities at the retail level. Over 5,200 miles of transmission lines make up the NPPD electrical grid system, which delivers power to about 600,000 Nebraskans.
APPENDIX 2: DESCRIPTION OF IS MEMBERS

- Basin Electric Power Cooperative - Basin Electric Power Cooperative (Basin Electric) is one of the largest electric generation and transmission (G&T) cooperatives in the United States. Basin is a not-for-profit generation and transmission cooperative incorporated in 1961 to provide supplemental power to a consortium of rural electric cooperatives. Basin has a diverse energy portfolio consisting of coal, gas, oil, nuclear, distributed, and renewable energy, including wind power. Basin is consumer owned by 137-member cooperative systems whose members’ service territories comprise 540,000 square miles in nine states. By end of year 2013 Basin Electric will operate 4,824 megawatts (MW) of wholesale electric generating capacity and have 5,289.2 MW of capacity within its generation portfolio. Basin owns 2,165 miles and maintains 2,250 miles of high-voltage transmission, and owns and maintains equipment in 70 switchyards and 149 telecommunication sites and serves 2.8 million electric consumers.

- Heartland Consumers Power District - Heartland is a non-profit public power district headquartered in Madison, South Dakota. Heartland is a public corporation and political subdivision of the State of South Dakota, formed in 1969 under South Dakota’s Consumers Power District statutes – Title 49, Chapters 35-40 – which is similar in structure to Nebraska public power entities. Heartland is a wholesale power supplier to 29 municipal systems in SD, MN and IA, five South Dakota state institutions and one cooperative – mostly supplemental to Western. These 35 customers represent load of 140 MW. Heartland is a minority owner of the Integrated System and most of their assets are jointly owned with other public entities.

- Western Area Power Administration (Western): Upper Great Plains (UGP) Region - The Upper Great Plains Region is one of four regions of the Western Area Power Administration. Western UGP has 378,000 square miles of service area including 118 substations and 7,920 miles of transmission lines which are federally owned. UGP sells power in Iowa, Minnesota, Montana, Nebraska, North Dakota, and South Dakota to wholesale customers such as towns; rural electric cooperatives; public utility and irrigation districts; Federal, state, and military agencies; Native American tribes; investor-owned utilities; power marketers; U.S. Bureau of Reclamation; and U.S. Army Corps of Engineers customers. UGP sells more than 9 billion kilowatt-hours of firm power generated from eight dams and power plants of the Pick-Sloan Missouri Basin Program-Eastern Division. This power is enough to serve more than 3 million households.
APPENDIX 3: DESCRIPTION OF ENTERGY

Entergy Corporation is an integrated energy company engaged primarily in electric power production and retail distribution operations. Entergy owns and operates power plants with approximately 30,000 megawatts of electric generating capacity, including nearly 10,000 megawatts of nuclear power, making it one of the nation’s leading nuclear generators. Entergy delivers electricity to 2.8 million utility customers in Arkansas, Louisiana, Mississippi and Texas. Entergy operates a system composed of approximately 15,500 miles of interconnected transmission lines at voltages of 69 kilovolt and above and approximately 1,500 substations across a 114,000 square mile area.
### ENTERGY/MISO INTEGRATION
#### Transition Period Cost Allocation – Non-MVPs

<table>
<thead>
<tr>
<th>Type and Location of Project</th>
<th>Approved Before Transition Period</th>
<th>Treatment During Transition Period</th>
<th>Treatment After Transition Period</th>
<th>Approved and/or Identified(^1) During Transition Period</th>
<th>Approved After Transition Period Ends</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Non-MVP</strong> projects</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>terminating First Planning Area</td>
<td>Allocated solely to First Planning Area</td>
<td>Allocated solely to First Planning Area</td>
<td>Allocated solely to First Planning Area</td>
<td>Allocated solely to First Planning Area</td>
<td>Allocated as applicable to both Planning Areas</td>
</tr>
<tr>
<td><strong>Non-MVP</strong> projects</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>terminating in Second Planning Area</td>
<td>Subject to South Planning Area pre-transition Tariff(s)</td>
<td>Allocated solely to Second Planning Area</td>
<td>Allocated solely to Second Planning Area(^1)</td>
<td>Allocated solely to Second Planning Area(^1)</td>
<td>Allocated as applicable to both Planning Areas</td>
</tr>
<tr>
<td><strong>Non-MVP</strong> projects</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>terminating in both Planning Areas</td>
<td>Not Applicable</td>
<td>Not Applicable</td>
<td>Allocated as applicable to both Planning Areas</td>
<td>Allocated as applicable to both Planning Areas</td>
<td>Allocated as applicable to both Planning Areas</td>
</tr>
</tbody>
</table>

Non-MVPs = Baseline Reliability Projects, Generator Interconnection Projects, and Market Efficiency Projects

\(^1\) Includes projects identified, but not yet approved, with in-service date no more than 5 years after end of transition period.

In MISO's tariff, the Midwest Planning Area is referred to as the First Planning Area and the South Planning Area is referred to as the Second Planning Area.

Source: Attachment FF-6, Section IV
### ENTERGY/MISO INTEGRATION
#### Transition Period Cost Allocation –MVPs

<table>
<thead>
<tr>
<th>Location of MVP Project</th>
<th>Treatment During Transition Period of Projects Approved</th>
<th>Treatment After Transition Period of Projects Approved</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Before Transition Period</td>
<td>During Transition Period</td>
</tr>
<tr>
<td><strong>MVP terminating in First Planning Area</strong></td>
<td>Allocated within First Planning Area</td>
<td>Allocated within First Planning Area</td>
</tr>
<tr>
<td><strong>MVP terminating in Second Planning Area</strong></td>
<td>Not Applicable</td>
<td>Allocated within Second Planning Area</td>
</tr>
<tr>
<td><strong>MVP terminating in both planning areas</strong></td>
<td>Not Applicable</td>
<td>Allocated as applicable to both Planning Areas</td>
</tr>
</tbody>
</table>

MVP = Multi-Value Projects  
FPA = First Planning Area or MISO Midwest  
SPA = Second Planning Area or MISO South

In MISO’s tariff, the Midwest Planning Area is referred to as the First Planning Area and the South Planning Area is referred to as the Second Planning Area.

Source: Attachment FF-6, Section IV
APPENDIX 4: PREVIOUS COST ALLOCATION AND INTEGRATION APPROACHES
4.1.1 NEBRASKA INTEGRATION

The members of the Nebraska Integration consist of: Omaha Public Power District (OPPD), Lincoln Electric System (LES), and Nebraska Public Power District (NPPD). A summary of each entity can be found in Appendix 1.

4.1.1.1 EVALUATION PROCESS

There was no formal, documented process SPP used for the Nebraska integration. After the Nebraska integration there was a request from SPP members to document the integration process which the Strategic Planning Committee (SPC) developed. The SPC further refined the integration process in July 2015 with the approval of SPC Task Force on New Members SPP Stakeholder Communication Process.

4.1.1.2 TRANSMISSION SYSTEM STUDY

A transmission system study was performed in 2008. The purpose of the transmission system study was to perform an evaluation of the Nebraska transmission system to ensure its transmission facilities met SPP criteria and NERC standards as interpreted by SPP.

4.1.1.3 COST ALLOCATION

The Nebraska entities joined SPP in 2009. The Nebraska entities paid all regional cost sharing for regional facilities to date, as well as in the future, and SPP members cost shared in one project NPPD was constructing. The Annual Transmission Revenue Requirement (ATRR) Nebraska cost shared was around $7 million and the SPP members cost shared 33% of phase one (1) of NPPD’s 345kV ETR project. The regional cost allocation methodology at this time was base plan funding that was approved in 2005 and allocated funding 33% regionally and 67% zonal based on a MW-Mile calculation.

4.1.2 INTEGRATED SYSTEM INTEGRATION

The IS consists of three (3) members: Basin Electric Power Cooperative, Heartland Consumers Power District, and Western Area Power Administration (Western) Upper Great Plains (UGP) Region. A summary of each entity can be found in the Appendix 2.

4.1.2.1 EVALUATION PROCESS

The following steps describe the evaluation process:

1. SPP Staff and the Transmission Working Group (TWG) evaluation of IS system.
2. SPP’s staff evaluation of cost and benefits of the IS joining SPP was shared with Stakeholders.
3. Evaluation of cost/benefits included transmission expansion, SPP administrative fee, transmission service revenue, reserve sharing, and market impacts.
4. Tariff revisions were approved by the Regional Tariff Working Group (RTWG), Markets and Operations Policy Committee (MOPC), SPP Board of Directors and Members Committee (BOD/MC).
5. Membership Agreement/Bylaw Changes were approved by Corporate Governance Committee (CGC), the SPP BOD/MC
6. RSC Discussion - Potential for new RSC membership.
7. BOD/MC approved Changes filed with and approved by FERC.

SPP used the member integration process approved by the SPC to assist SPP Staff with the process of working with the IS to explore membership in SPP. This is the same process used with prospective members since the Nebraska entities joined SPP. This evaluation process involves the SPC appointing a sub-group to assist SPP Staff with regular reports to the SPC. This process was also used during negotiations with Entergy on prospective membership. The SPC chair appointed a sub-group in September, 2012 to assist SPP Staff based on the interest expressed by the IS. SPP Staff reviewed progress with the SPC in all meetings including three meetings (May 1, 2013, October 17, 2013 and January 16, 2014) that were in executive session. State regulatory staff were included in the executive sessions held as part of the May 1, 2013 and October 17, 2013 meetings. In these meetings SPP Staff received comments and adjustments to the proposals in negotiations with the IS entities. SPP Staff validated with SPC the proposals provided to the IS parties in the negotiations. The SPC further refined the integration process in July 2015 with the approval of SPC Task Force on New Members SPP Stakeholder Communication Process. (See attachment

As part of the discussions at the SPC, SPP Staff provided two analyses needed for SPP members:

- Cost/Benefit Analysis for SPP from IS joining SPP
- Transmission Analysis to ensure that IS transmission facilities met SPP standards (SPP Criteria and SPP interpretation of NERC Standards) (See below at 5.1.2.2)

4.1.2.2 TRANSMISSION SYSTEM STUDY

The purpose of the transmission system study was to perform an evaluation of the IS transmission system in the event a decision was made to join the SPP RTO. There were two main objectives of the System Study:
• Evaluate the IS transmission system to determine whether it met SPP’s Planning Criteria and NERC TPL Standards
• Identify the SPP “need-by” dates of the transmission projects provided by the IS in relation to the assumed October 2015 integration date

4.1.2.3 COST ALLOCATION

During the negotiation process an assumed integration date was set for October 1, 2015, based on estimated time needed for IS parties to obtain approval and also complete integration activities to integrate into SPP. Costs for any upgrades to the IS system needed before the integration date are paid for by the IS members only, while costs for any upgrades to the SPP system needed before the integration date are paid for by SPP members only. Costs for any upgrades to the IS system and/or the SPP system needed after the integration date are cost shared according to SPP Highway/Byway methodology.

The one exception to this cost allocation methodology relates to a portion of the FSE, which only applies to Western-UGP. The FSE is set forth in Section 39.3(e) of the SPP OATT and includes modifications to Schedule 11 and Attachment AE.

The FSE applies to the transmission of Federal Power from Western-UGP resources to meet Western-UGP’s Statutory Load Obligations under the Tariff. Western-UGP is exempt from the Schedule 11 Region-wide Charge for delivery of its Federal Power from Western-UGP resources to its Statutory Load Obligations internal to the Upper Missouri Zone (UMZ) or delivery across the UMZ to obligations external to the UMZ or external to SPP. Western-UGP will pay regional Schedule 11 charges for any deliveries of power to loads other than its Statutory Load obligations internal to the UMZ and for any deliveries of power from resources other than its own hydropower resources. Western-UGP is responsible for its share of Schedule 11 Zonal charges. The FSE will not apply to Basin Electric or Heartland or any other entity embedded within Zone 19 nor will it apply to Western-UGP’s marketing activities in the Integrated Marketplace to either purchase or sell energy.

Additionally, any load served by Western-UGP in the Western Interconnection utilizing transmission facilities in the UMZ will not be subject the Schedule 11 Region-wide Charge to the extent the load is served only by resources in the Western Interconnection.

An additional part of the FSE is that Western-UGP is also exempt from congestion and marginal loss charges for deliveries of Federal Power from Western-UGP resources across the UMZ to its Statutory Load Obligations.
Western-UGP is responsible for providing SPP with energy losses in accordance with Attachment M of the Tariff.

4.2 ENTERGY MEMBERSHIP PROPOSAL

In 2010, SPP proposed membership to the Entergy Corporation. A summary describing this entity can be found in Appendix 3.

4.2.1 EVALUATION PROCESS

SPP used the member integration process approved by the SPC to assist SPP Staff with the process of working with Entergy to explore membership in SPP. This is the same process used with prospective members since Nebraska entities joined SPP. This process involves the SPC appointing a sub-group to assist Staff with regular reports to the SPC. The proposal SPP offered the IS was the same proposal offered to Entergy.

4.2.2 TRANSMISSION SYSTEM STUDY

A transmission system study was performed on the Entergy system. The purpose of the transmission system study was to perform an evaluation of the Entergy transmission system to ensure their transmission facilities met SPP Criteria standards and NERC TPL standards.

4.2.3 PROPOSED COST ALLOCATION

The cost allocation proposal SPP offered Entergy was the same proposal that was subsequently offered to the IS. This involved an integration date where Entergy and SPP would use Highway/Byway cost allocation methodology after Entergy’s facilities came under the SPP Tariff. Any upgrades needed to the Entergy System prior to the integration date would be paid for by Entergy and any upgrades needed to the SPP System prior to the integration date would be paid for by SPP members. Entergy decided to join the Midcontinent Independent System Operator (MISO) in April 2011, ending negotiations with SPP.

4.3 OTHER RTO REGIONS

4.3.1 ENTERGY / MISO INTEGRATION

The expansion of MISO’s market operations to a new South Region in December 2013 introduced customers in that region to benefits that Midwest Region customers enjoy which include greater reliability, lower costs, and improved oversight. To ensure the benefits accruing to one region are not adversely affected by transmission expansion and upgrade costs in another, MISO developed a transition plan for extending transmission planning and cost allocation practices to its South Region in a just and reasonable manner. The FERC approved on April
19, 2012 MISO’s proposal for a five-year transition period, beginning when the first Entergy Operating Company joins the MISO Market.  

The cost allocation rules that apply to network upgrades approved before, during, and after the five-year transition period are described in Attachment FF-6 of MISO’s Tariffs. Tables summarizing the cost allocation methodology during and after the five-year transition period can be found in Appendix 3.

In general, projects approved prior to the transition period will be subject to the tariff under which they were approved and will not be eligible for cost sharing between the Midwest and South regions. Similarly, the costs of projects approved during the transition period that are located wholly in one region will remain in the region and will not be subject to cost sharing between the two regions. To the extent the projects approved during the transition period terminate in both regions, the associated costs will be allocated to both regions during and after the five-year transition period, in accordance with the cost allocation rules under Attachment FF of MISO’s tariffs. The only exception to this cost allocation approach is the treatment of costs of Multi-Value Projects under certain circumstances. Multi-Value Projects (MVP) address energy policy laws and/or provide widespread benefits across MISO footprint and encompass all voltages. Under MISO tariffs, these upgrades are generally subject to 100% regional funding.

During the five-year transition period, MISO will attempt to develop a portfolio of MVPs approved before or during the transition period for the combined Midwest and South Regions (Combined MVP Portfolio) that satisfies a cost benefit test, such that: 1) each zone in the Midwest Region does not experience a degradation in the net benefits estimated for MVPs approved prior to the five-year transition period; and 2) each zone in the South Region will receive a net benefit from the Combined MVP Portfolio. If MISO identifies a Combined MVP Portfolio that satisfies the cost-benefit test by the end of the five-year transition period, then the cost of MVPs approved by MISO before or during the five-year transition period that terminate exclusively in either region will be shared across both regions. Such regional cost allocation will be phased in over eight years at gradually increasing annual percentages of 12.5 percent.

In the event that the Combined MVP Portfolio does not satisfy the cost-benefit test, but the MVPs approved during the transition period that terminate exclusively in

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either region satisfy the existing benefit criteria of Attachment FF in the MISO tariffs, the associated costs would be shared across the regions pursuant to Attachment FF. On the other hand, if MVPs approved during the transition period that terminate exclusively in either region cannot satisfy the cost-benefit test or the conditions for cost sharing across the regions in Attachment FF, the costs of such MVPs will be allocated solely to the region in which the MVP upgrade terminated. Lastly, if the Combined MVP portfolio does not satisfy the cost-benefit test, the costs of MVPs approved before the transition period (and included in the Combined MVP Portfolio) that, by their nature, terminate only within the Midwest Region, would not be shared across both regions after the five-year transition period.

The costs of network upgrades approved after the end of the five-year transition period will be allocated across the combined regions pursuant to Attachment FF of the MISO tariffs.

4.3.2 PJM INTEGRATIONS

4.3.2.1 ATSI INTEGRATION

On December 17, 2009, FERC approved a regional transmission organization (RTO) realignment request submitted by American Transmission Systems, Inc. (ATSI) to withdraw from MISO and join PJM. The reasons cited by ATSI in support of its proposed realignment request were the elimination of operational efficiencies and reduction in congestion.

As part of its RTO realignment request, ATSI requested a waiver of PJM’s annual allocation of regional transmission expansion plan costs, under Schedule 12 of PJM’s tariffs, for transmission expansion projects approved by PJM prior to ATSI’s integration into PJM. In the event the waiver request was denied, ATSI’s parent entity, FirstEnergy Services Company (First Energy), sought a finding that allocation of costs to ATSI for legacy projects in PJM is unjust, unreasonable, and unduly discriminatory. Due to the differing cost methodologies in MISO and PJM, First Energy asserted that the ATSI would be required to pay twice in conjunction with its planned realignment because it would have to pay under both allocations, for projects planned and approved in separate RTOs over the same period. MISO allocates its costs on the basis of a one-time allocation at the time specific projects are approved while PJM reallocates costs annually to each transmission owner based on its share of PJM’s total load that is within PJM.

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8 ATSI Realignment Order at paragraph 2.
9 Id. at paragraph 3.
10 Id. at paragraph 21.
as of the date of the allocation. FERC rejected ATSI’s waiver request and dismissed First Energy’s complaint.\footnote{Id. at paragraph 7.}

With respect to cost allocation, FERC required ATSI to honor its financial obligations to MISO for costs associated with transmission facility additions incurred under MISO tariffs prior to withdrawal from MISO\footnote{Id. at paragraph 51.} although FERC determined that ATSI was not responsible for the costs of the Multi-Value Projects (MVPs) approved by the MISO Board prior to its withdrawal.\footnote{Midwest Independent Transmission System Operator, Inc., 153 FERC ¶61,101 (2015) at paragraphs 69-78.} In addition, ATSI is required to pay the system-wide costs in PJM under Schedule 12 of PJM’s tariff, which would include system-wide costs for legacy projects approved by PJM prior to ATSI’s integration into PJM on June 1, 2011. FERC recognized that the cost allocation methodologies for the two RTOs were different and that both methodologies had been accepted by FERC as just and reasonable and not unduly discriminatory.

Furthermore, FERC concluded as a basis for its decision that “cost causation also includes the allocation of “costs to serve” that party including those facilities that benefit the party. Even if a new member was not using the system when a particular project was planned or authorized, the new member may nevertheless use and benefit from the new facility in the future.”\footnote{ATSI Rehearing Order at paragraph 26.} FERC also noted that “ATSI and the PJM transmission owners are free to negotiate the terms of ATSI’s entrance into PJM to the extent that ATSI brings benefits to the existing PJM transmission grid” and that “given the voluntary nature of RTOs, such a collaborative effort is the most appropriate manner of resolving such cost issues.”\footnote{ATSI Realignment Order at paragraph 114; ATSI Rehearing Order at paragraph 23.} On July 18, 2014, the D.C. Circuit Court of Appeals upheld FERC’s decision on the cost allocation issue.\footnote{FirstEnergy Service Co. v. F.E.R.C., 758 F.3d 346 (2014).} 

\subsection*{4.3.2.2 DUKE ENERGY INTEGRATION}

On October 21, 2010, in response to a regional transmission request (RTO) realignment request from Duke Energy Ohio and Duke Energy Kentucky, FERC authorized the two companies to withdraw from the MISO RTO and join the PJM RTO, effective January 1, 2012.\footnote{Duke Energy Ohio, Inc., et al., 133 FERC ¶ 61,058 (2010).} Duke Ohio and Duke Kentucky are wholly owned subsidiaries of Duke Energy Corporation and are principally engaged in providing integrated retail and wholesale electric utility service in Ohio and Kentucky, respectively.
With respect to cost allocation, Duke Energy Ohio and Duke Energy Kentucky were required to honor their financial obligations to MISO, including the transmission cost allocations for projects approved by the MISO Board of Directors prior to the Duke Companies’ integration into PJM. However, as in the case of ATSI, the Duke Companies were not responsible for the costs of the Multi-Value Projects (MVPs) approved by the MISO Board prior to their withdrawal from MISO.\textsuperscript{18} As far as cost allocation for PJM projects are concerned, Duke Companies are subject to Schedule 12 of the PJM tariffs which allocates costs to the Duke Companies for the projects approved in PJM regardless of whether the projects were approved prior to the companies’ integration into PJM (legacy projects) or are approved after their integration into PJM.\textsuperscript{19}

\begin{footnotesize}

\textsuperscript{19} Duke Energy Ohio, Inc., et al., 139 FERC ¶ 61,068 (2012); Duke Energy Ohio, Inc., et al., 151 FERC ¶ 61,029 (2015)
\end{footnotesize}
Aggregate Study Scope presentation – short version

Adam McKinnie

RSC Meeting

4-25-2016
Purpose of presentation

• In ten slides or less, I am going to tell you:
  • Why the RSC should care about this issue
  • Explain what an Aggregate Study is
  • Explain what the Safe Harbor is
  • Explain Aggregate Study criteria
  • Propose next steps for CAWG
Why important to the RSC

- Essentially, this is a COST ALLOCATION issue
- Cost Allocation is under RSC authority, per RSC bylaws
- The decisions made by the RSC / CAWG on this issue will determine: What transmission project costs are paid for by companies purchasing transmission service versus the SPP footprint?
What is an Aggregate Study

• Aggregate Study assesses what transmission projects are necessary to sell reservations to move energy around the SPP system, as well as who pays for those projects.

  – The reservations to move energy around the system are called “Transmission Service Requests”
Who pays in an Aggregate Study

• Once an Aggregate Study determines which transmission projects are necessary to fulfill all the reservations, costs are initially assigned to different TSR purchasers
• If those purchasers meet certain criteria, all or some costs of transmission projects initially assigned to TSR purchasers will be paid for by the region up to a certain amount, based on the size of their reservation.
• This certain amount of costs is the SAFE HARBOR
Safe Harbor

• An Aggregate Study assigns costs of transmission projects needed to sell TSRs to different entities purchasing transmission service
  – Sometimes no additional transmission projects are needed for the TSR to be granted
• Depending on the circumstances, a certain amount of the costs of the transmission projects from an aggregate study may be “base plan funded*” – paid for by the region based on voltage of the project under the “Highway Byway” cost allocation.
• Costs not paid by the region are paid by the TSR purchaser.
• The amount approved for “base plan funding” is called the “Safe Harbor”

*“base plan funding” has meant cost allocation methodologies other than Highway / Byway prior to 2010
Aggregate Study Criteria

• TSR purchasers have to meet up to 3 criteria to be eligible for a Safe Harbor
  – If they do not meet the applicable criteria, TSR purchasers can ask for a waiver to be eligible for a Safe Harbor
Aggregate Study Criteria

• The 3 criteria to be eligible for a Safe Harbor:
  – If the TSR is granted, the utility will not have over 20% of their designated resources from wind (only applies to a TSR related to designating wind as a Designated Resource)
  – 5 year minimum term of commitment for the TSR
  – If the TSR is granted, the utility will not have Designated Resources greater than 125% of their forecasted load
Proposed CAWG Next Steps

• CAWG can request data on the three criteria
  – How close utilities are to the “designated resources up to 125% of forecasted load” criteria
  – How close utilities are to having 20% of their designated resources from wind
  – Get a breakdown of TSR request length

• CAWG can request data on impact of changing the three criteria, or adding any new criteria
Additional Resources

• There is a longer version of this presentation, developed with the assistance of CAWG members, CAWG stakeholder participants, and SPP Staff that provides significant additional detail

• This presentation may be useful to refer to in later discussions on this topic
Questions?
Capacity Margin Task Force (CMTF) Update
Outline

- Background
- Load Responsible Entity
- Planning Reserve Margin Requirement
- Planning Reserve Assurance Policy
- Deliverability Study
- CMTF Recommendation
Capacity Margin Task Force

Purpose
Updating SPP Capacity Margin requirements and methodology

Members

Tom Hestermann (SEPC), Chair  Jason Atwood (NTEC), Vice-Chair  L. Nickell (SPP), Secretary
Bill Bojorquez (Hunt Trans)  Clint Bruhn (LES)  Walt Cecil (MoPSC)
Jason Chaplin (OCC)  Bill Dowling (MWE)  J. Grotzinger (MJMEUC)
Zac Hager (OGE)  Brad Hans (MEAN)  Randy Hughes (COI)
Jon Iverson (OPPD)  Jim Jacoby (AEP)  Rob Janssen (Dogwood)
Lloyd Linke (WAPA)  Pat Lyons (NMPRC)  Pat McCool (KCPL)
Aaron Ramsdell (BEPC)  Randy Root (GRDA)  John Stephens (CUS)
Jon Sunneberg (NPPD)  Bryan Taggert (WR)  Todd Tarter (EDE)
Joe Taylor (Xcel)  John Varnell (Tenaska)  Mike Wise (GSEC)
CMTF Establishment

Needed to Evaluate Resource Adequacy in SPP

- Significant transmission expansion in place
- Expanding footprint and operational changes
- SPP became the Balancing Authority in March 2014
- Issues raised with existing SPP Criteria language
- Capacity margin requirement unchanged since 1998
- CMTF formed in July 2014
CMTF Recommended Policies

- Load Responsible Entity
- Planning Reserve Margin Requirement
- Deliverability Study
- Planning Reserve Assurance Policy
CMTF Balance Goals

Reliability

Economics
Load Responsible Entity (LRE)
Problem Statement

• Current SPP Criteria obligates Load Serving Members to meet SPP’s reserve margin requirement

• Not all load in the SPP Balancing Authority footprint is served by an SPP member
LRE Solution

• CMTF proposes that all load serving obligations in the SPP Balancing Authority include an obligation to meet SPP’s Planning Reserve Margin (PRM) requirement

• Approved the LRE whitepaper
  • Defines the Load Responsible Entity as “any Asset Owner participating in the Integrated Marketplace with registered physical assets that are either load or firm Export Interchange Transactions”
  • Assigns responsibility for PRM to the Market Participant for the LRE
  • Recognizes that SPP currently has contractual obligations with the MP, but not the LREs
Planning Reserve Margin Requirement
Current Requirement

- SPP Planning Criteria section 4.1.9 states, “Each Load Serving Member’s Minimum Required Capacity Margin shall be twelve percent. If a Load Serving Member’s System Capacity for a Capacity Year is comprised of at least seventy-five percent hydro-based generation, then such Load Serving Member’s Minimum Required Capacity Margin for that Capacity Year shall be nine percent”

- SPP’s minimum capacity margin requirement of 12% has been in place since October 1, 1998, prior to that it was set at 15%

- The current 12% capacity margin requirement is equivalent to a reserve margin requirement of 13.6%
Analysis

• “Limbo Study” performed to determine Loss of Load Expectation (LOLE) at various reserve margin levels
  • Monte Carlo simulations, each conducted at 3,000 or more trials
  • Assumptions vetted by CMTF, ORWG, and GWG
  • Three years studied: 2016, 2017, and 2020
  • Topology updated to reflect latest planning models being used in 2016 ITPNT assessment
  • Third-party assessment of SPP’s Limbo Study performed

• Additional sensitivities performed based on feedback of CMTF, ORWG, and GWG

• Assessed load diversity impacts on non-coincident peak application of the reserve margin requirement
“Limbo” Study Results

Reserve Margin “LIMBO” Study Results

LOLE (Days per ten years)

Reserve Margin (%)

- 2016 LOLE Results
- 2017 LOLE Results
- 2020 LOLE Results

SPP Criteria

<table>
<thead>
<tr>
<th>Reserve Margin (%)</th>
<th>2016</th>
<th>2017</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.53%</td>
<td>1.73</td>
<td>0.92</td>
<td>0.45</td>
</tr>
<tr>
<td>8.70%</td>
<td>0.46</td>
<td>0.45</td>
<td>0.37</td>
</tr>
<tr>
<td>9.89%</td>
<td>0.27</td>
<td>0.19</td>
<td>0.15</td>
</tr>
<tr>
<td>11.11%</td>
<td>0.18</td>
<td>0.15</td>
<td>0.08</td>
</tr>
</tbody>
</table>
Sensitivity Analysis Summary (2017)

Sensitivity Analysis performed at 9.89% Reserve Margin for 2017

- 9.00% Max Load Uncertainty: 0.59
- 3.95% Max Load Uncertainty: 0.19
- 2011 load & wind shapes: 0.56
  5 year averaged load & wind shapes: 0.19
- Monitoring 100kV and above: 0.24
- Monitoring 230kV and above: 0.19
- Additional Retirements Orginal Scope Retirements: 0.21
- Summer Season 6/22 to 9/8: 0.21
- Summer Season 6/1 to 9/30: 0.19

LOLE (Days per 10 Years)
Sensitivity Analysis Summary (2020)

Sensitivity Analysis performed at 9.89% Reserve Margin for 2020

- 9.00% Max Load Uncertainty
- 3.95% Max Load Uncertainty

- 2011 load & wind shapes
- 5 year averaged load & wind shapes

- Monitoring 100kV and above
- Monitoring 230kV and above

- Additional Retirements
- Original Scope Retirements

- Summer Season 6/22 to 9/8
- Summer Season 6/1 to 9/30

LOLE (Days per 10 Years)

Values:
- 0.38
- 0.15
- 0.12
- 0.01
- 0.01
- 0.15
- 0.15
- 0.15

Diagram shows sensitivity analysis results with various factors contributing to the reserve margin.
Combined Sensitivity Analysis

LOLE at 12.0% Reserve Margin

- LIMBO Study Assumptions
- Combined Sensitivities

LOLE (Days per ten years)

<table>
<thead>
<tr>
<th>Year</th>
<th>SPP Criteria</th>
<th>2017</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>0.85</td>
<td>0.04</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.22</td>
<td></td>
</tr>
</tbody>
</table>

Study Year
Comparison of Regional PRM Requirements (13.6% RM)

2017 Reserve Margin Requirements for NERC Entities

Red columns represent non-coincident
Blue columns represent coincident load

Data sourced from 2015 NERC LTRA

* Based on an observed diversity factor of 3.7% for 2015
Comparison of Regional PRM Requirements (12% RM)

2017 Reserve Margin Requirements for NERC Entities

Red columns represent non-coincident
Blue columns represent coincident load

Data sourced from 2015 NERC LTRA

* Based on an observed diversity factor of 3.7% for 2015
# PRM Reduction Cost Savings

## Inputs

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Reserve Margin</td>
<td>13.6%</td>
</tr>
<tr>
<td>Proposed Reserve Margin*</td>
<td>12.0%</td>
</tr>
<tr>
<td>Net CONE (CT)</td>
<td>$109.6 ($/kW-yr)</td>
</tr>
</tbody>
</table>

## Results

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Capacity Cost Savings (2015 $)</td>
<td>$86.14 $M</td>
</tr>
<tr>
<td>40-yr Capacity Cost Savings (2015 $)</td>
<td>$1,347.22 $M</td>
</tr>
</tbody>
</table>

* Reducing reserve margin requirement from 13.6% to 12.0% results in approximately 900 MW of capacity reduction
CMTF PRM Recommendation Vote

- CMTF straw poll results from Dec 3rd meeting

<table>
<thead>
<tr>
<th>Reserve Margin (%)</th>
<th>Votes For</th>
<th>Votes Against</th>
<th>Abstentions</th>
<th>Percentage of votes for reserve margin</th>
</tr>
</thead>
<tbody>
<tr>
<td>13.0%</td>
<td>20</td>
<td>1</td>
<td>1</td>
<td>95.2%</td>
</tr>
<tr>
<td>12.5%</td>
<td>16</td>
<td>3</td>
<td>3</td>
<td>84.2%</td>
</tr>
<tr>
<td>12.0%</td>
<td>13</td>
<td>6</td>
<td>3</td>
<td>68.4%</td>
</tr>
<tr>
<td>11.5%</td>
<td>8</td>
<td>12</td>
<td>2</td>
<td>40.0%</td>
</tr>
</tbody>
</table>

- CMTF approved a reduction of SPP’s PRM requirement from 13.6% to 12.0% on Feb 16, 2016
  - 22 votes cast
  - Unanimous approval with 2 abstentions
Planning Reserve Assurance Policy (PRAP)
Planning Reserve Assurance Policy

Current PRM Enforcement

- Potential revocation of membership
- Potential imposition of NERC reliability standard penalty provisions in SPP’s Attachment AP, if violation occurs

Shortfalls of Current Enforcement

- Too extreme
- Occurs too late to assure adequate levels of PRM are maintained
- Entities with capacity in excess of SPP’s PRM requirement are not compensated for their contribution to SPP’s PRM
Planning Reserve Assurance Policy

CMTF Proposal

- Payment based on Cost of New Entry (CONE) from deficient entities to entities with excess capacity, based on forecasts
- Payment scaled based on the potential for reduced reliability in the SPP region

Benefits of the Planning Reserve Assurance Policy

- Establishes a reasonable enforcement mechanism
- Ensures an adequate level of reliability is maintained
- Incentivizes proper resource planning
- Compensates those with excess capacity when needed to offset an entity’s deficiency
Planning Reserve Margin Assurance Policy Timeline

- **Resource Adequacy Workbook sent to LRE's**
  - 1/18

- **Resource Adequacy Workbook due from LRE's**
  - 2/15

- **Pre-Season Reserve Margin validation completed by SPP staff**
  - 3/18

- **Begin working with each LRE to reconcile Reserve Margin calculations**
  - 3/25

- **Final Reserve Margin validation released**
  - 4/15

- **Deadline for submitting deficiency contracts to SPP**
  - 5/15

- **Issue Assurance Policy charges to LRE's that are deficient**
  - 6/1

- **Post Season validation started**
  - 10/1

- **Post Season validation completed**
  - 10/21

- **Draft Reserve Margin LRE comparison report released**
  - 11/18

- **Final LRE Reserve Margin outlook report released**
  - 12/9

**2017**

- **Resource Adequacy Workbook Educational Session with LRE's**
  - 1/15

- **Annual CONE Payment Calculation**
  - 11/30
Deliverability Study

• Current SPP Planning Criteria 4.1.3 requires firm transmission service be obtained for load and capacity obligations.

• With expected adoption of the PRAP, the Deliverability Study policy is proposed to provide an optional means of arranging for planning reserve margin capacity that recognizes:
  • The operation of the Integrated Marketplace
  • Performance of SPP’s planning studies
Deliverability Concepts

• Each LRE must report capacity committed to supply its load and PRM obligations

• Firm transmission service must exist to support delivery of capacity to an LRE’s peak load obligation

• LREs may use firm transmission service or contractual arrangement with generating capacity that has been deemed deliverable through the deliverability study for their reserve margin obligation

• SPP will rely on its planning processes to both determine deliverability capacity amounts and ensure deliverability through transmission expansion
Deliverability Study Timeline

- Deliverability study performed for current year + 1 and current year + 2: 6/1/2016
- Internal review of Deliverability study results: 8/1/2016
- Deliverability study results provided to Generator Owners: 9/25/2016
- Resource Adequacy Workbook sent to LRE's: 1/15
- Resource Adequacy Workbook due from LRE's: 2/15
- Begin working with each LRE to reconcile Reserve Margin calculations: 3/25
- SPP Board of Directors approves NTCs: 4/25/2016
- GOs determine available capacity and contract with LREs short on capacity for PRM obligation: 10/1/2016
- SPP releases final deterministic PRM calculation on LRE data for Planning Reserve Assurance: 4/15
CMTF Recommendation
CMTF Proposed Policy Package

• The CMTF established four primary areas of policy development as the top priorities:
  • Load Responsible Entity
  • Planning Reserve Margin Requirement
  • Planning Reserve Assurance Policy
  • Deliverability Study

• These policies identify **who** is responsible for resource adequacy, **what** the resource adequacy requirement is, and **how** and **when** the resource adequacy requirement can be and should be met

• The CMTF believes the policies are dependent on each other to yield the intended economic and reliability benefits and believes the policies should be approved and implemented collectively
CMTF Recommendation

The Capacity Margin Task Force recommends approval of the following items to become effective for the summer of 2017

- LRE whitepaper

- Planning reserve margin requirement for entities comprised of at least seventy-five percent hydro-based generation to remain 9.89% and for all other entities to be 12.0%

- “Capacity margin” terminology be replaced with “reserve margin” terminology throughout SPP Planning Criteria and SPP Tariff language

- Planning Reserve Assurance Policy

- Deliverability Study
CMTF Recommendation Votes

- March 15, 2016 - CMTF unanimously approved with no abstentions
- April 5, 2016 - CAWG unanimously approved the following motion with no abstentions
  - The CAWG recommends approval of the policies developed by the CMTF and recommends that they be approved as a package by the RSC. Further, the CAWG believes that the policies are interrelated and should only be considered as a package. It is the CAWG’s position that the proposal provides benefits to ratepayers without jeopardizing reliability.
- April 12, 2016 - MOPC approved CMTF recommendation with 1 no vote & 5 abstentions
- April 13, 2016 - SPC unanimously approved CMTF recommendation with 1 abstention
## RARTF Members

<table>
<thead>
<tr>
<th>Name</th>
<th>Affiliation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steve Stoll, Chair</td>
<td>Missouri Public Service Commission</td>
</tr>
<tr>
<td>Richard Ross, Vice Chair</td>
<td>American Electric Power</td>
</tr>
<tr>
<td>Shari Albrecht</td>
<td>Kansas Corporation Commission</td>
</tr>
<tr>
<td>Steve Lichter</td>
<td>Nebraska Power Review Board</td>
</tr>
<tr>
<td>Lamar Davis</td>
<td>Arkansas Public Service Commission</td>
</tr>
<tr>
<td>Phil Crissup</td>
<td>Oklahoma Gas and Electric</td>
</tr>
<tr>
<td>Bill Grant</td>
<td>SPS Xcel Energy</td>
</tr>
<tr>
<td>Bary Warren</td>
<td>South Central MCN</td>
</tr>
<tr>
<td>Harry Skilton</td>
<td>SPP Board of Directors</td>
</tr>
</tbody>
</table>
RECENT MEETINGS/TOPICS
March 7, 2016
• Conference Call / Web Ex
• RR-155 Potential RCAR Remedies
  – Task Force worked through the language for a new Business Practice that describes each of the potential remedies listed in the 2012 RARTF Report (attached RR)
    ▪ Remedy Definitions
    ▪ Remedy Approval Process
    ▪ Remedy Implementation Process
  – Finalized language on April 12, 2016 – Vote 8-1 (Xcel SPS)
  – Stakeholder Review/Approval Process
    ▪ July MOPC and RSC
Upcoming RARTF Events

• May 3, 2016 – F2F Meeting in Dallas, TX
  – Review draft RCAR results

• RCAR Schedule
  ▪ Stakeholder feedback - May/Early June
  ▪ Finalize RARTF Approval - Late June/Early July
  ▪ RTWG – June 23
  ▪ MOPC – July 12
  ▪ RSC - July 18
  ▪ BOD – July 25
  ▪ Review with other stakeholder groups as requested
Revision Request Form

<table>
<thead>
<tr>
<th>SPP STAFF TO COMPLETE THIS SECTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>RR #: 155</td>
</tr>
<tr>
<td>RR Title: Potential RCAR Remedies</td>
</tr>
<tr>
<td>Impact Analysis Required?</td>
</tr>
<tr>
<td>□ No</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SUBMITTER INFORMATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Name: Ben Bright, on behalf of the RARTF</td>
</tr>
<tr>
<td>Company: SPP</td>
</tr>
<tr>
<td>Email: <a href="mailto:bbright@spp.org">bbright@spp.org</a></td>
</tr>
<tr>
<td>Phone: 501-614-3965</td>
</tr>
</tbody>
</table>

Only Qualified Entities may submit Revision Requests. Please select at least one applicable option below, as it applies to the named submitter(s).

- □ SPP Staff
- □ SPP Market Participant
- □ SPP Member
- □ An entity designated by a Qualified Entity to submit a Revision Request “on their behalf”
- □ SPP Market Monitor
- □ Staff of government authority with jurisdiction over SPP/SPP member
- □ Rostered individual of SPP Committee, Task Force or Working Group
- □ Transmission Customers or other entities that are parties to transactions under the Tariff

<table>
<thead>
<tr>
<th>REVISION REQUEST DETAILS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Requested Resolution Timing: □ Normal □ Expedited □ Urgent Action</td>
</tr>
<tr>
<td>Reason for Expedited/Urgent Resolution:</td>
</tr>
</tbody>
</table>

Type of Revision (select all that apply):

- □ Correction
- □ Clarification
- □ Design Enhancement
- □ New Protocol, Business Practice, Criteria, Tariff
- □ NERC Standard Impact (Specifically state if revision relates to/or impacts NERC Standards, list standard(s))
- □ FERC Mandate (List order number(s))

<table>
<thead>
<tr>
<th>REVISION REQUEST RISK DRIVERS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Are there existing risks to one or more SPP Members or the BES driving the completion of this RR? □ Yes □ No</td>
</tr>
<tr>
<td>If yes, provided details to explain type of risk and any timelines associated:</td>
</tr>
<tr>
<td>□ Compliance (Tariff, NERC, Other)</td>
</tr>
<tr>
<td>□ Reliability/Operations</td>
</tr>
<tr>
<td>□ Financial</td>
</tr>
</tbody>
</table>

SPP Documents Requiring Revision:

Please select your primary intended document(s) as well as all others known that could be impacted by the requested revision (e.g. a change to a protocol that would necessitate a criteria or business practice revision).

- □ Market Protocols Protocol Section(s): Protocol Version:
- □ Criteria Criteria Section(s): Criteria Date:
- □ Tariff (OATT) Tariff Section(s):
- □ Business Practice Business Practice Number:
Objectives of Revision Request:
Describe the problem/issue this revision request will resolve.

This new Business Practice will lay the foundation for documenting the potential RCAR remedies and clarify the process that will be used when implementing a remedy in the RCAR process.

Describe the benefits that will be realized from this revision.

The benefit of the new Business Practice is to document a process that will be followed in analyzing potential remedies and the process by which these potential remedies will be approved and implemented for zones that fall below the approved threshold in the RCAR process.

REVISIONS TO SPP DOCUMENTS
In the appropriate sections below, please provide the language from the current document(s) for which you are requesting revision(s), with all edits redlined.

Market Protocols

SPP Tariff (OATT)

SPP Criteria

SPP Business Practices

Business Practice #155

Background
In approving the Highway/Byway cost allocation methodology for the Southwest Power Pool, Inc. (SPP) Regional Transmission Organization (RTO), the Federal Energy Regulatory Commission (FERC) in Attachment J Section III.D of the SPP OATT, also approved a requirement that SPP conduct a review of the “reasonableness of the regional allocation methodology and factors (X% and Y%) and the Zonal allocation methodology at least once every three years.” This review is required to “determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct (NTC) issued after June 19, 2010 to each pricing Zone within the SPP Region.” Thus, the purpose of this analysis is to measure the “cost allocation impacts” of SPP’s Highway/Byway methodology by Zone. The review is hereinafter referred to as the “Regional Cost Allocation Review” (RCAR).

SPP’s Open Access Transmission Tariff (Tariff or OATT) specifically requires that “the Markets and Operations Policy Committee (MOPC) and Regional State Committee (RSC) will define the analytical methods to be used” in conducting the Regional Cost Allocation Review. As a result, the Regional Allocation Review Task Force (RARTF) was created as part of the SPP stakeholder process to develop the “analytical methods” used for the review.
The Regional Cost Allocation Review process is defined in the RARTF Final Report that was published and approved in January 2012. In this report, the RARTF makes a number of recommendations as to how SPP should conduct the Regional Cost Allocation Review. This includes a recommendation of applying ten principles, used by the RARTF, as a guide to conducting the review. These principles include: simplicity; acknowledgment of the “roughly commensurate” legal standard; equity over time; the use of the best quantifiable information available; consistency; transparency; stakeholder input; the use of real dollars values; and the inclusion in the review of Board approved transmission plans with more weight being given to nearer term projects.

Through the work of the Economic Studies Working Group (ESWG) certain benefits will be measured in the review. These benefits include, but are not limited to: adjusted production costs; positive impact on capacity required for losses; improvements in reliability; remedy benefits in future reviews; reduction of emission rates and values; reduced operating reserves; improvements to import/export limits; and public policy benefits.

Additionally, the RARTF recommended a Benefit to Cost (B/C) threshold that serves as the basis by which SPP and stakeholders evaluate each zone in the RCAR analysis. Zones that fall below the defined threshold of 0.8 (“Deficient Zones”) require that SPP evaluate and study potential remedies for that zone. The potential remedy would be utilized to bring the Deficient Zone(s) to the threshold level or higher.

The RARTF also prescribed some potential remedies, listed in order of preference that SPP staff could evaluate. These include, but are not limited to:

<table>
<thead>
<tr>
<th>Remedy</th>
<th>Entity with Authority/Duty to Implement</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Acceleration of planned upgrades;</td>
<td>SPP BOD</td>
</tr>
<tr>
<td>(2) Issuance of NTCs for selected new upgrades;</td>
<td>SPP BOD</td>
</tr>
<tr>
<td>(3) Apply Highway funding to one or more Byway Projects;</td>
<td>RSC, SPP BOD &amp; FERC</td>
</tr>
<tr>
<td>(4) Apply Highway funding to one or more Seams Projects;</td>
<td>RSC, SPP BOD &amp; FERC</td>
</tr>
<tr>
<td>(5) Zonal Transfers (similar to Balanced Portfolio Transfers) to offset costs or a lack of benefits to a zone;</td>
<td>RSC, SPP BOD &amp; FERC</td>
</tr>
<tr>
<td>(6) Exemptions from cost associated with the next set of projects;</td>
<td>RSC, SPP BOD &amp; FERC</td>
</tr>
<tr>
<td>(7) Change Cost Allocation Percentages.</td>
<td>RSC, SPP BOD &amp; FERC</td>
</tr>
</tbody>
</table>

The process for conducting a RCAR analysis has been documented in the RARTF Final Report with subsequent guidance provided to staff by the RARTF. In addition, SPP shall provide a “lessons learned” guidance document following each RCAR analysis as an enhancement for consideration in future RCAR analyses. This Business Practice will provide the details regarding each potential remedy listed above and detail the approval and implementation process that will be followed. It is also important to note that the list of potential remedies above is not exhaustive and an alternative remedy(s) could be recommended by the RARTF. Any alternative remedy would require a detailed approval and implementation plan to be included in the RCAR Report and approved through a stakeholder process.
Starting the Review Process

At least one year prior to the start of a cost allocation review, the MOPC and RSC shall create, or reaffirm, the RARTF. The RARTF shall be responsible for: (1) working with SPP Staff to create the criteria for the RCAR analysis, (2) reviewing the results of the analysis, and (3) presenting the results of the RCAR study to the MOPC and RSC.

Detailed Remedy Analysis

Remedy #1 - Acceleration of Planned Upgrades

Definition of Remedy: Acceleration of a planned upgrade\(^1\) would occur when an upgrade has already been approved for construction by the SPP BOD and by building the approved upgrade sooner than the original need by date. This remedy will allow for a Deficient Zone to realize the benefits of that specific upgrade sooner than planned.

Approval and Implementation of Remedy: Staff will work with a Deficient Zone(s) to assess if by changing the need by date for any upgrade would provide additional benefits to the Deficient Zone while still meeting the needs of the system. If such an upgrade is determined by the RARTF to be a potential remedy for a Deficient Zone, the change in the upgrade’s need by date may be recommended by the RARTF to the MOPC and RSC. No additional studies are planned to assess this remedy other than a RCAR analysis. The approval process of this remedy will be the endorsement by the RSC and the MOPC to the SPP BOD. Upon approval by the SPP BOD, SPP shall issue a modification of the upgrade’s NTC. This remedy would remain in effect for the life of the upgrade(s).

Remedy #2 – Issuance of NTC for a Selected New Upgrade

Definition of Remedy: Issuance of NTC for a selected new upgrade would occur when a new transmission upgrade will provide benefits to one or more Deficient Zones.

Approval and Implementation of Remedy: Staff will work with any Deficient Zone to assess if any transmission upgrade can provide additional benefits to the Deficient Zone while still meeting the needs of the system. These projects would be recommended by the RARTF to the MOPC and RSC to be included in any planning study process outlined in the tariff. If the proposed remedy is included as part of the final portfolio of transmission projects for the SPP BOD approval, then upon the SPP BOD approval of the portfolio of projects an NTC or RFP will be issued. This remedy would remain in effect for the life of the upgrade(s).

Remedy #3 – Apply Highway Funding to one or more Byway Projects

Definition of Remedy: Changing the cost allocation of an upgrade for a Deficient Zone between the voltages of 100 kV and 300 kV\(^2\) to 100% regional allocation\(^3\). Changing the cost allocation of an upgrade to 100% regional allocation would provide benefit to a Deficient Zone by removing costs that would normally be assigned to that Zone and allocated to the entire SPP footprint.

Approval and Implementation of Remedy: To be eligible, the upgrade must have been built or approved for construction through the SPP Planning process. At the conclusion of an RCAR analysis, the RARTF may recommend that an upgrade may have its cost allocation methodology changed to a 100% regional allocation.

\(^1\) For purposes of this Business Practice, an “upgrade” shall mean any new transmission facility or upgrade to an existing SPP Network facility as defined in the SPP Tariff.
\(^2\) The cost allocation for an upgrade that is operated at voltages between 100 kV and 300 kV is 33% Regional and 67% to the Zone where the upgrade is built. This is generally referred to as “Byway” funding.
\(^3\) The cost allocation for an upgrade that is operated at voltages above 300 kV is allocated 100% to the entire SPP footprint and is generally referred to as “Regional” or “Highway” funding.
The RARTF would present a recommendation to the CAWG and the MOPC for their consideration. The final RARTF recommendation would then be presented and debated with all appropriate stakeholder groups including the RSC and the BOD prior to any external filings. In the end, pursuant to Section 7.2 of the SPP Bylaws, any change to cost allocation provisions including this RCAR remedy, would require that this remedy along with any necessary Tariff language or waiver request to be approved by the RSC and filed with FERC. In addition, this remedy shall be reviewed and evaluated for reauthorization at each subsequent RCAR analysis.

If, following each subsequent RCAR analysis, the remedy is not recommended by RCAR to be reauthorized; appropriate filings shall be made at the FERC to revert the cost allocation to the standard Zonal allocation. If, following each subsequent RCAR analysis, the remedy is recommended for reauthorization, the remedy would remain in effect until such time as the cost allocation is changed by the FERC.

**Remedy #4 – Apply Highway Funding to one or more Seams Projects**

For Order 1000 Interregional Projects: Projects approved within the Order 1000 processes with both MISO and SERTP are eligible to have Highway funding with no additional FERC approval needed.

For Non-Order 1000 Seams Projects: Projects approved outside of an interregional Order 1000 process will need to get FERC approval for any change in cost allocation. The process for Remedy #3 above would be used for these projects.

**Remedy #5 – Zonal Transfers (similar to Balanced Portfolio Transfers) to offset costs or lack of benefits to a zone**

Definition of Remedy: Zonal transfers would occur when a Deficient Zone’s allocation of cost is reduced by decreasing the amount of the Deficient Zone’s zonal Annual Transmission Revenue Requirement (ATRR) by a set amount and adding that amount to the Base Plan Regional ATRR, in a similar manner to Balanced Portfolio Transfers.

Approval and Implementation of Remedy: At the conclusion of an RCAR analysis, the RARTF may determine that a zonal transfer would be an appropriate remedy for a Deficient Zone. The RARTF would present a recommendation to the CAWG and the MOPC for their consideration. The final RARTF recommendation would then be presented and debated with all appropriate stakeholder groups including the RSC and the BOD prior to any external filings. In the end, pursuant to Section 7.2 of the SPP Bylaws, any change to cost allocation provisions including this RCAR remedy, would require that this remedy along with any necessary Tariff language or waiver request to be approved by the RSC and filed with FERC. In addition, this remedy shall be reviewed and evaluated for reauthorization at each subsequent RCAR analysis. If, following each subsequent RCAR analysis, the remedy is not recommended by RCAR to be reauthorized; appropriate filings shall be made at the FERC to revert the cost allocation to the standard Zonal allocation. If, following each subsequent RCAR analysis, the remedy is recommended for reauthorization, the remedy would remain in effect until such time as the cost allocation is changed by the FERC.

**Remedy #6 – Exemptions from costs associated with a future set of base plan funded projects**

Definition of Remedy: Exemptions from costs from a future set or subset of base planned funded projects would occur when a Deficient Zone is not allocated some or all of its regular allocation of a set of approved upgrades.

Approval and Implementation of Remedy: At the conclusion of an RCAR analysis, it may be determined that exempting a Deficient Zone from cost allocation for a set of projects would be the appropriate remedy. The RARTF would present a recommendation to the CAWG and the MOPC for their consideration. The final RARTF recommendation would then be presented and debated with all appropriate stakeholder groups including the RSC and the BOD prior to any external filings. In the end, pursuant to Section 7.2 of the SPP Bylaws, any change to cost allocation provisions including this RCAR remedy, would require that this remedy along with any necessary Tariff language or waiver request to be approved by the RSC and filed with FERC. In addition, this remedy shall be reviewed and evaluated for reauthorization at each subsequent RCAR analysis. If, following each subsequent RCAR analysis, the remedy is not recommended by RCAR to be reauthorized; appropriate filings shall be made at the FERC to revert the cost allocation
to the standard Zonal allocation. If, following each subsequent RCAR analysis, the remedy is recommended for reauthorization, the remedy would remain in effect until such time as the cost allocation is changed by the FERC.

**Remedy #7 – Change Cost Allocation Percentages**

Definition of Remedy: Changing cost allocation percentages would occur when the RCAR analysis indicates that the current cost allocation structure is no longer assigning costs to all Zones in a manner that is roughly commensurate to the calculated benefits.

Approval and Implementation of Remedy: The RARTF would present a recommendation to the CAWG and the MOPC for their consideration. The final RARTF recommendation would then be presented and debated with all appropriate stakeholder groups including the RSC and the BOD prior to any external filings. In the end, pursuant to Section 7.2 of the SPP Bylaws, any change to cost allocation provisions including this RCAR remedy, would require that this remedy along with any necessary Tariff language or waiver request to be approved by the RSC and filed with FERC.
SEVENTY-FIVE YEARS OF RELIABILITY THROUGH RELATIONSHIPS
Regional State Committee

Lanny Nickell

April 25, 2016
Ensuring a reliable tomorrow

2016 Integrated Transmission Planning Near-Term (ITPNT) Assessment
2016 ITPNT Background

- ITPNT is a near-term reliability assessment performed annually
- Reliability needs defined per SPP, NERC, company-specific planning criteria
  - Transmission overloads
  - Voltage violations
- Solutions to reliability needs
  - 69 kV and above transmission solutions
  - Non-transmission solutions in the form of Operating Guides
- Economic needs or solutions not evaluated
Key Differences from 2015 ITPNT

- Footprint expansion
- NTC Re-evaluation projects removed from base models
- Consolidated Balancing Authority (CBA) weighting
- Operating guides submitted as DPPs applied during solution development
- Winter peak cases
- Significant base case issues
  - 2015 ITPNT (9 Thermal and 127 Voltages)
  - 2016 ITPNT (31 Thermal and 900 Voltages)
2016 ITPNT Process Milestones

- Project Scope Development (Nov 2014 – Mar 2015)
- Model Development (Mar – Jun 2015)
- Needs Assessment (Jul – Sep 2015)
- DPP Window and Cure Period (Oct 1 – Nov 13, 2015)
- Solution Development (Nov 2015 – Mar 2016)
- Study Cost Estimates (Jan – Mar 2016)
- Stakeholder Feedback (Feb – Mar 2016)

Milestone: Draft Project Portfolio posted 1/27/2016
Study Cost Estimate 1st requests sent – due 2/24/2016 1/27/2016

Milestone: Project Scope Approved - MOPC/Board
March 2015

Milestone: Models approved by TWG
6/30/2015

Milestone: Project Scope Approved - TWG
3/16/2015

Milestone: Needs Assessment posted 9/30/2015

Milestone: All Study Cost Estimates due 3/15/2016

Milestone: Final Reliability Assessment March 2016

Milestone: MOPC Endorsement
April 2016

Milestone: Board Approval
April 2016

2016 ITPNT Portfolio Summary

- 2017-2020 timeframe
- 262 unique potential issues mitigated
- 49 projects/86 upgrades
- $229.2M net total study cost
  - New NTCs: $362.6M
  - Change in Modified NTCs: $6.8M
  - Withdrawn NTCs: $(140.2M)
# 2016 ITPNT STEP Impact

<table>
<thead>
<tr>
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<tbody>
<tr>
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<td>($ 140,224,519)</td>
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<tr>
<td>Net Total</td>
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</table>
ITPNT Upgrade Cost by Voltage Class

2016 ITPNT NTC Costs

Dollars ($M)

- New NTC
- Modified NTC
- Withdrawn NTC

- 345 kV: $128
- 230 kV: $72
- 161 kV: $1
- 138 kV: $61
- 115 kV: $157
- 69 kV: $41

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ITPNT Cost Allocation – Regional vs. Zonal

2016 ITPNT Cost Allocation
Regional vs. Zonal

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<td>Net Total</td>
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| **Zonal**      |             |
| New NTC        | $217        |
| Modified NTC   | $80         |
| Withdrawn NTC  | $107        |
| Net Total      | $190        |
ITPNT Upgrades by Need Date and Total Dollar

2016 ITPNT Upgrades
Need Year and Total Dollars

Number of New Upgrades

Dollars ($M)

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<th>Number of Upgrades</th>
<th>Total Dollars</th>
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<td>2018</td>
<td>4</td>
<td>$19</td>
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<td>2019</td>
<td>1</td>
<td>$1</td>
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<tr>
<td>2020</td>
<td>11</td>
<td>$28</td>
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</table>

Legend:
- Blue: Upgrades by Need Year
- Red: Total Dollars
# 2016 ITPNT Net Investment by State

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<tr>
<th>State</th>
<th>New NTC</th>
<th>Modified NTC (Net Change)</th>
<th>Withdrawn NTC</th>
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<td>Total</td>
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<td>$6,803,083</td>
<td>($140,224,519)</td>
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ITPNT Rate Impacts By Zone

2016 ITPNT Net Rate Impacts by Zone
1000 kWh per Month Retail Residential Consumer
(2020$ per month)

<table>
<thead>
<tr>
<th>Zone</th>
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<th>New</th>
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Approvals and Next Steps

• MOPC Approval 4/12/16
  • 2016 ITPNT Study completion per SPP OATT Attachment O Section III
  • 2016 ITPNT Project Portfolio

• 2016 ITPNT Project Portfolio will be presented to SPP Board of Directors for approval on 4/26/16
Appendix
ITPNT Needs by Owner

2016 ITPNT NEEDS

NUMBER OF NEEDS

0 20 40 60 80 100 120

OWNER

AEPW BEPC GMO GRDA LE-REC MIDW OKGE OMPA OPPD SPS SUNC WAPA WFEC

Unique Thermal  Unique Voltage

9 11 8 4 1 2 3 4 6 2 1 25 21 2 7 7 14 16 101
SEVENTY-FIVE YEARS OF RELIABILITY THROUGH RELATIONSHIPS
Integrated Marketplace Update

Bruce Rew, PE

Vice President, Operations
SPP Integrated Marketplace Update

• Marketplace Highlights Over Last 12 Months
• Marketplace Statistical Information
• Marketplace Wind Peak and Penetration
• Enhancements under development
Marketplace Over Last 12 Months

• 172 Market Participants
  • 110 financial only and 62 asset owning
    • Added 6 new Market Participants since January report

• SPP BA has successfully maintained NERC control performance standards (BAAL & CPS)

• High System availability
  • Day-Ahead Market was only delayed from posting once in the first quarter of 2016
  • Real-Time Balancing Market has successfully solved 99.90% of all intervals
Integrated Marketplace Savings

- Market continues to provide savings even with extremely low natural gas prices below $2
- First year net savings calculated to be $380 million
- 2015 annual net savings calculated to be $422 million
Dispatch by Fuel Type

Real-Time

Generation (TWh)


- Other
- Gas-SC
- Gas-CC
- Coal
- Hydro
- Renewable
- Wind
- Nuclear

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Fuel on the Margin in RT

% Intervals on Margin

- **Other**
- **Gas**
- **Coal**
- **Wind**

![Bar chart showing fuel usage from January 2015 to March 2016.](chart.png)
Real-Time versus DA pricing
% Contribution of LMP Difference

MCC: Marginal Congestion Cost
MLC: Marginal Loss Cost
MEC: Marginal Energy Cost
Marketplace Operational Highlights

  - Compared to 2014/2015 winter peak of 36,995 MW on January 8, 2015

- Total of 12,400 MW of installed and operational wind capacity to date
  - Additional 574 MW of wind registered as of 4/1/2016 (12,974 MW)

- Additional 140 MW of solar plants registered on 4/1/2016
  - Previous total for registered solar was 50 MW
Wind Output: January – March 2016

• Wind output represents the total real-time output of all wind generators in the SPP market at a point in time.

• Max wind output: 10,809 MW 3/28 @21:22
  • All-Time Max: 10,809 MW 3/28/2016

• Min wind output: 264 MW 1/12 @12:00
  • All-Time Min*: 30 MW 3/1/2015

• Q1 Average wind output: 5,422 MW

*Since Integrated Marketplace Go-Live 3/1/2014
Wind Penetration: January – March 2016

- Wind penetration represents the instantaneous wind output divided by the total load. (Wind Gen/SPP Load)

  - Max % penetration: 45.1% of load 3/7 @01:03
  - All-Time Max: 45.1% of load 3/7/2016
  - Min % penetration: 0.8% of load 1/12 @11:54
  - All-time Min*: 0.1% of load 3/1/2015
  - Q1 Average % penetration: 20.0% of load

*Since Integrated Marketplace Go-Live 3/1/2014
January – March 2016

Daily Averages

- Average of Wind Output MW
- Average of Wind Penetration

Wind MW

Wind Penetration

0% 5% 10% 15% 20% 25% 30% 35% 40% 45% 50% 55%


Average of Wind Output MW
Average of Wind Penetration

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### January – March 2016 Summary

<table>
<thead>
<tr>
<th></th>
<th>Wind Output</th>
<th>Wind Penetration (% of Load)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Max</strong></td>
<td><strong>10,809 MW</strong> 3/28 @21:22</td>
<td>45.1% 3/7 @01:03</td>
</tr>
<tr>
<td><strong>Min</strong></td>
<td><strong>264 MW</strong> 1/12 @12:00</td>
<td>0.8% 1/12 @11:54</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td><strong>5,422 MW</strong></td>
<td><strong>20.0%</strong></td>
</tr>
</tbody>
</table>
Recently Implemented:

- Real-Time Data Precision Enhancement
- Short-Term Intra-Day RUC (STRUC)
- Misc Markets UI/API Improvements

On The Way (Target June 1, 2016 Implementation):

- ECC Changes/Schema Changes
- MCE Performance Enhancements (in preparation of ECC)
- Misc MP Requested Enhancements

Tentative Near Term:
(Target Nov 1, 2016 Implementation)

- ECC Changes as needed
- Misc Markets UI/API Improvements
SPP Wind Integration Study Update

- New Wind Integration Study to evaluate operational impacts of higher penetration levels of wind in SPP to 60%
- 2015 Wind Summit established study process and methodology used
- Draft study posted for review by stakeholders in January. Final study targeted for completion by mid-2016
- 2 day Wind Integration Summit held in Little Rock on February 17-18
  - Almost 200 attendees in person/phone
  - Great feedback on study results
Wind Integration Report

- Study determined operational needs for high penetration levels of renewables
- SPP Working Groups reviewed report and endorsed
  - Operations Reliability Working Group
  - Transmission Working Group
  - Economic Studies Working Group
- Presented to Market Operations Policy Committee
  - Recommended name change to reflect analysis
  - Accelerate Re-evaluation of two projects
Summary of Recommendations

1. Installing voltage supporting capabilities
2. Enhance real-time operational monitoring tools
3. Providing flexibility in operations dispatch
4. Enhanced planning criteria for more detailed scenarios
5. Expedite Integrated Transmission Planning projects (Accelerate Re-Evaluation)
   1) Sundown – Amoco 230 kV (SPS)
   2) Cimarron - Draper 345 kV (OGE)
6. Evaluate impacts of solar PV in combination with wind
7. Evaluate PMU applications for real-time situational awareness
Transmission Planning Improvement Task Force (TPITF)

RSC Meeting
April 25, 2016
Brian Gedrich, Chair
TPITF Scope

Evaluate and propose recommendations on:

- The appropriateness of the planning cycle and assessments
  - Effectiveness of using production cost modeling in more assessments
  - Development, use, and weighting of futures, scenarios and sensitivities
  - Metrics used to evaluate proposed projects
  - Planning the transmission system beyond the traditional planning criteria of first contingency (“N-1”)
- Utilization of data, including data collected by operations to ensure consistency in the planning process
- The methodologies and modeling practices used in the planning, compliance, and model building groups to ensure effectiveness and consistency between processes
Recommendations

- Implement annual ITP planning cycle
- Standardized study scope
- Establish common reliability planning model for all SPP planning assessments
- Utilize a holistic approach to planning
- Create a Staff/Stakeholder accountability program
Annual ITP Planning Cycle

- Desired State
  - Single ITP planning study incorporating near- and long-term views
    - Annual planning report and NTC recommendations
  - Remove ITP20 from planning cycle
    - Perform separately no more than once every five years unless directed by the SPP Board
  - Annual 10-year assessment
    - Combines the ITPNT, ITP10, and portions of the TPL-001-4 into one assessment
  - Overlapping planning cycles
    - Three 10-year assessments over a three year period
Standardized ITP Assessment Scope

• Desired State
  o Standardized Scope
    ▪ Review and approval of methodologies and criteria that guide study processes
    ▪ Simplify scope development process; eliminate need to review and approve items annually
    ▪ Help provide the consistency members seek for the planning studies
  o Assumptions Document
    ▪ Fully outline and describe scope items that require Stakeholder review and approval with each new study
    ▪ Maintain flexibility to make needed changes for those specific scope items
  o Leverage SPP’s Revision Request (RR) Process for scope changes
    ▪ Govern how the submitted changes will be received, reviewed, approved, and implemented
    ▪ Proper Stakeholder vetting and approval
Common Planning Model

• Desired State
  o Base Reliability Model
    ▪ Reduce bookend scenario model sets to single expected case scenario
    ▪ Represents SPP load responsible entities serving network load with firm network resources only
    ▪ Non-coincident peak load forecasts
    ▪ Assumed long-term firm transmission service
  o Economic Model
    ▪ Identify and assess solutions to economic and public policy needs of the SPP system
    ▪ Developed for three study years (Years 2, 5, and 10)
    ▪ Up to three economic models will be developed for the reference case future in Years 5 and 10
  o CBA Reliability Model
    ▪ Represents SPP load responsible entities serving network load with both firm and non-firm resources under market based construct
    ▪ Built from Economic model
Holistic Planning Process

• Desired State
  o Reliability and Compliance Assessments
    ▪ Reliability needs produced from base reliability and CBA reliability models; model set
    ▪ Compliance needs produced from the TPL base reliability and short circuit models
  o Public Policy Assessments
    ▪ Public policy needs considered in the economic model runs for each Future in Years 2, 5, and 10
  o Economic Assessments
    ▪ Economic needs determined based on congestion in the SPP region
  o Operational Assessments
    ▪ Chronic operational issues with a significant financial or reliability impact identified in the operation of the integrated marketplace
  o Solution Development
    ▪ A single Detailed Project Proposal (DPP) window
    ▪ Staff will evaluate DPPs and Staff solutions to develop the most cost-effective solutions to all needs
Staff/Stakeholder Accountability

• Desired State
  o Stakeholders/Staff implement an *accountability assurance program*
Implementation

Final set of recommendations to the MOPC, SPC, and SPP BOD in July 2016 for approval.

- Forward recommendations to the appropriate Stakeholder groups for process development and implementation
- TPITF will work with impacted Stakeholder groups to develop timelines for the development, review, and implementation of the changes to the planning process
- TPITF will work with Staff and Stakeholders to determine potential resource and other budgetary impacts of the recommended process improvements
- Workshops will be held to inform and educate Stakeholders on the proposed improvements prior to July 2016 MOPC
TRANSMISSION PLANNING IMPROVEMENT TASK FORCE (TPITF)

SPP Planning Process Improvement Recommendations

Published on April 5, 2016
# Revision History

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<th>Revision Date</th>
<th>Author</th>
<th>Change Description</th>
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Transmission Planning Improvement Task Force (TPITF) Recommendations Whitepaper

Purpose

Since the adoption of the Integrated Transmission Planning process, there has been an improvement in the planning of needed transmission. The ITP process has helped to determine the transmission needs for the SPP region and facilitated investment in over $5.5 Billion of cost effective transmission. SPP has now completed two cycles of the ITP and is now in the midst of the 2017 ITP10. The experience of stakeholders and the SPP has shed light on the strengths of the ITP process as well as potential improvements that could be made.

The Transmission Planning Improvement Task Force (TPITF) was assembled by the SPP Strategic Planning Committee (SPC) and the Market and Operations Policy Committee (MOPC) and given the responsibility for developing recommendations that will improve the regional planning processes. The objective was to make the SPP transmission planning process more responsive to the effects of the continued growth of SPP’s transmission system, changes in the SPP markets, as well as the challenges and opportunities presented by changing federal and state energy and environmental regulations, and NERC compliance requirements. The TPITF recommendations are intended to represent a consolidated, coordinated approach in planning, managing, and maintaining the SPP transmission system, and improve the existing processes, with a particular emphasis on any progress that may be made to increase the availability of transmission service to SPP’s customers without unduly compromising system reliability. The recommendations in this report are intended to enable the cost-effective use of capital-intensive generating resources for the benefit of all end-use customers in the SPP footprint and to further develop and enhance policies, tools, and practices to optimize the use of the transmission system. The TPITF was tasked with reviewing, evaluating, and proposing recommendations on the following:

1. The methodologies and modeling practices used in the Generator Interconnection Studies; Aggregate Transmission Service Studies; Integrated Transmission Planning (Near Term, 10, and 20), SPP TPL Compliance Assessments and the MDWG model development process to ensure effectiveness, consistency, and to determine if any gaps exist between the various processes. Where appropriate, the TPITF will collaborate with the SPP committees and working groups involved in the development and approval process for SPP planning.

2. Utilization of data, including data collected by operations that will benchmark, to the best ability, the real-time and planning horizon assessments to ensure consistency in the planning process.

3. The appropriateness of the planning cycle and assessments, including but not limited to, the effectiveness of using production cost modeling in more assessments; development, use, and weighting of futures, scenarios and sensitivities; the metrics used to evaluate proposed projects, in particular those that evaluate the impact on rate payers, and planning the transmission system beyond the traditional planning criteria of first contingency (“N-1”) in accordance with the approved NERC Standard TPL-001-4.

1 A copy of NERC Standard TPL-001-4 can be found at the following location: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-001-4&title=Transmission System Planning Performance Requirements&jurisdiction=United States
The TPITF has developed a set of five recommendations to accomplish this scope of work that will be discussed in detail throughout this whitepaper. These five recommendations are as follows.

1. Replace the current ITP schedules with an annual planning cycle
2. Create a standardized scope
3. Establish a common planning model for use across the various SPP planning process
4. Utilize a holistic approach to planning
5. Create a Staff/Stakeholder accountability program
Annual ITP Planning Cycle

Purpose

The current ITP planning cycle consists of the ITPNT, ITP10, and ITP20 assessments performed over the course of three years. The TPITF sees value in performing a single ITP planning study that incorporates near- and long-term views with the study producing a planning report and transmission project recommendations on an annual basis. The efficiencies gained through the combination of the ITPNT and ITP10 assessment processes and the increased frequency of the completion of a forward-looking, annual planning study will help address members’ requests for additional synergy and flexibility within SPP’s planning process.

Current State

Planning Cycle

Section III of Attachment O of SPP’s Open Access Transmission Tariff (Tariff) describes the Integrated Transmission Planning (ITP) process as “…an iterative three-year process that includes the 20-Year, 10-Year, and Near Term Assessment.” The 20-Year (ITP20) and 10-Year Assessments (ITP10) are each performed once every three years as part of the three-year planning cycle with the ITP20 generally performed in the first half of each planning cycle. The Near Term Assessment (ITPNT) is performed on an annual basis to maintain system reliability in the short-term. In aggregate, these assessments evaluate the cost-effectiveness of proposed solutions needed in Years 2, 5, 10, and 20 over a 40-year horizon. The cycle is shown below and iterated every three years.

<table>
<thead>
<tr>
<th>Year 1</th>
<th>Year 2</th>
<th>Year 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>ITPNT</td>
<td>ITPNT</td>
<td>ITPNT</td>
</tr>
<tr>
<td>ITP20</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ITP10</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The ITP20 is performed in the first half of the 3-year planning cycle to guide the development of plans for the ITP10 and ITPNT assessments. The ITP20 is primarily a strategic economic study designed to identify a transmission expansion portfolio containing Extra High Voltage (EHV) projects that would provide the flexibility to address reliability needs, support policy initiatives, and enable economic opportunities in the SPP transmission system under a wide range of future system scenarios within the studied 20-year horizon. The ITP20 portfolio is not likely to result in the issuance of Notifications to Construct (NTCs) for specific projects, but rather is a longer-term strategic vision expected to better inform planning decisions in the 5-10 year horizon including the “right-sizing” of projects in support of potential system needs observed in the 20-year horizon.

The ITP10 is performed in the second half of the 3-year planning cycle. The ITP10 is intended to study in further detail a subset of future scenarios studied in the ITP20. The ITP10 is designed to develop a transmission expansion portfolio containing primarily 100 kV and above projects needed to address reliability needs, support policy initiatives, and enable economic opportunities in the SPP transmission system within the studied 10-year horizon. This portfolio of projects is likely to be recommended for NTCs.

The ITPNT is performed annually over the 3-year planning cycle. Unlike the ITP20 and ITP10, the ITPNT does not assess economic or public policy needs, but instead focuses exclusively on the reliability needs of the system associated with forecasted load growth and maintenance of long-term firm transmission service within the studied 5-year horizon.
TPITF Issues Related to Current Planning Cycle

The TPITF identified a number of issues related to the current planning cycle that inhibit the flexibility, quality, and timeliness of the SPP planning process. While the complete issues list can be found in Appendix C, issues related to the planning study cycle are summarized as follows:

- The 3-year planning cycle is too long and is inflexible in addressing system needs.
- The frequency of the 10-year planning assessment (once every 3 years) is inadequate.
- The ITP20 is performed too frequently based on practical value compared with the time and cost to perform the assessment.
- Performing the planning assessments separately reduces the opportunities for synergy in addressing the reliability, public policy, compliance, and economic needs of the SPP system with NTCs.

Desired State

Proposed Planning Cycle

The TPITF proposes an ITP assessment process that produces an annual report and transmission expansion plan. The proposed planning cycle, as illustrated below, will consist of scope development and reliability and economic model builds prior to the planning assessment. Planning models for succeeding studies will be built concurrently with the in-process study to allow the annual performance of the 10-year assessment. The cycle will iterate in this fashion producing an annual report in perpetuity. Further details can be found in the Transition and Implementation section.

The annual assessment cycle addresses Stakeholder concerns that the current planning process takes too long by reducing the planning cycle from 36 months to 12. This is achieved primarily by three changes to the existing process. First, the TPITF proposes removing the ITP20 from the standard ITP planning cycle. While the TPITF recognizes the ITP20 provides significant strategic value, the deliverable...
of the study is informational and may not need to be refreshed with triennial frequency. Due to the intense resource usage and the desire to reduce the duration of the planning cycle, but yet maintain the value of the ITP20, the TPITF recommends removing the ITP20 from the planning cycle and performing it separately no less than once every five years unless directed by the SPP Board. Performance of the ITP20 more or less frequently would require specific direction from the Strategic Planning Committee (SPC) and approval by the SPP BOD. Second, the remaining 18-month cycle will become an annual 10-year assessment that combines the ITPNT, ITP10, TPL-001-4 Short Circuit and portions of the TPL-001-4 Steady State assessments into one assessment, which is discussed in further detail in the Holistic Planning Process section. This change is intended to increase synergy by performing the planning assessments in unison. Third, the planning cycles will overlap by 12 months producing three 10-year assessments over a three year period as opposed to just one 10-year assessment in that same timeframe with the current ITP process. This approach addresses the goal of increasing the frequency of the 10-year assessments for reliability, public policy, and economic needs.
Standardized ITP Assessment Scope

Purpose

A large concern for SPP Staff and TPITF members is the amount of SPP Stakeholder and Staff time spent during each study process reviewing and approving scope items that tend to remain the same from study to study. The TPITF recommends the review and standardization of study scope items that remain relatively unchanged throughout each study iteration. This standardization will provide specific details around each scope item and eliminate the need for repetitive reviews and approvals. Stakeholders will retain the ability to modify standardized scope items by using the SPP Revision Request process as discussed in more detail below.

An additional benefit of standardization will be an increase in the consistency of how the studies are performed year over year which will help facilitate more detailed project analysis.

Current State

Integrated Transmission Planning Manual²

The Integrated Transmission Planning Manual (ITP Manual) is a comprehensive document describing the model building and assessment processes of the ITPNT, ITP20, and ITP10 studies. It also includes language describing futures development, the Order 1000 process, and the deliverables for each of the assessments. While the ITP Manual goes to great length to describe the numerous aspects of the assessments, it is written in a fashion that leaves several scope items open for a range of interpretation. This results in the need for working group review and approval with each ITP cycle. As a result, specific detail is drafted in study scopes that are then circulated through the corresponding working groups, including MOPC, for approval.

Study Scope Development and Approval

The scope development processes between the ITPNT and ITP10 are similar in the way the scope documents are created but differ in how they are approved. For both processes, the scope documents are developed during the initial planning phases of the studies. These documents are developed by SPP Staff and reviewed and approved by the appropriate working groups before moving on to MOPC and the SPP BOD for final approvals. Where the processes differ is in the level of detail incorporated for each scope item. The scope for the ITPNT is constructed to include the final process details for each item so that the final approval of the scope solidifies the scope for the remainder of the study. The ITP10’s approach differs in that the scope is constructed at a high-level with specific criteria surrounding each scope item formulated during the study process at a time before the corresponding actions occur. While a high-level scope is approved on the front-end of the ITP10 study process, specifics are not always reviewed and approved until after the study process has commenced and those scope-specific processes are ready to commence.

TPITF Issues Related to Study Scopes

The TPITF identified a number of issues related to study scopes that inhibit the flexibility, quality, and timeliness of the SPP planning process. While the complete issues list can be found in Appendix C, issues related to the planning study cycle are summarized as follows:

• There is inconsistency from study to study in how some scope items are implemented. The scope can change mid-process due to a change in the expectations of members or conflicting expectations among members. This can cause difficulty with building consensus toward the approval of resultant transmission plans.
• Scope review and approval by working groups can take a long time and cause delays in the process. Scope approval, including individual scope items, can take several working group meetings before approval is granted creating a bottleneck in the study schedule.
• The lack of standardization in the study scope makes it difficult to estimate the amount of SPP and member resources needed to complete the study.

Desired State

Standardized Scope

The review and approval of methodologies and criteria that guide study processes will be included in the ITP Manual as standard study scope items. These are processes that will remain the same under typical/normal circumstances from study to study. Outside of minor modifications, these items will not require the same level of scrutiny and vetting other scope items like the definition of study futures may require. Standardizing these planning principles will simplify the scope development process, eliminate the need to review and approve these items annually, and help to provide the consistency members seek for the planning studies.

Assumptions Document

An assumptions document will be developed to fully outline and describe those study scope items that will require Stakeholder review and approval with each new study. These items will be approved by the appropriate working groups during the scope development phase of the planning cycle. Scope items such as the definitions of futures or scenarios and sensitives may change with each study iteration in order to provide the appropriate context under which to assess the future performance of the existing transmission system and any needed improvements. For the 2017 ITP10 Assessment, the futures were modified to reflect the EPA’s Clean Power Plan. Maintaining the ability to change these assumptions from study to study will provide the flexibility needed for the long-term transmission planning process.

The TWG and ESWG will review and approve the scope items that will be standardized and the scope items that will be a part of the assumptions document and update the ITP Manual accordingly. The TPITF recommends moving the revised ITP Manual under the SPP Planning Protocols.

Revision Request (RR) Process for Scope Changes

Modifications to the standardized scope document will be submitted through the SPP Revision Request (RR) process to govern how the submitted changes will be received, reviewed, and approved. The RR process is a key component of SPP’s Stakeholder processes and allows Stakeholder input into decision making. It will place guidelines around the approval and implementation of study scope changes. The requests will be made via SPP’s Request Management System (RMS) which will allow for the tracking and reporting of scope revision submissions.

This process will give Stakeholders the ability to submit scope revisions for review by other Stakeholders without interrupting the study process which will decrease the mid-process disruptions that have been experienced in past studies. Approved revisions will be incorporated into the scope of the subsequent study.
The TPITF believes the leveraging of the RR process will appropriately address member concerns while reducing the considerable amount of time it has taken in past studies to finalize the study scope due to numerous revisions submitted by Stakeholders.

The TPITF envisions the use of the RR process to address improvements to the foundational scope items standardized within the ITP Manual. The TPITF recognizes the importance of Stakeholder input into the scope development process; however, it is the Task Force’s desire to see that substantive changes receive proper Stakeholder vetting and approval before implementation.

Standardized scope items will retain flexibility by granting the appropriate working group the ability to provide guidance on items as prescribed by the ITP Manual. An example of this flexibility may be with the standardizing of the scope item Fuel Prices. Standardized language may include the mechanism for setting fuel prices. Per the scope, the selected index would always be used for pricing information, however, the actual price of natural gas may change year-over-year. As the natural gas fuel prices change, the recommended prices would become a part of the assumptions while the standardized scope item would remain unchanged. If a Stakeholder recommends the use of another source for pricing information, that recommendation would be submitted through the RR process for proper Stakeholder vetting and approval.
Common Planning Model

Purpose

The SPP Modeling department in conjunction with the Model Development Working Group (MDWG) is responsible for developing the SPP Steady-State, Short Circuit, and Dynamics models. These model sets serve as the basis for further refinement into the base models for ITP and TPL Steady State assessments. The Economic Planning department is responsible for constructing the Economic model that is used during performance of the ITP10 study. The TPITF Scope document lists as one of its three objectives the “Utilization of data, including data collected by operations that will benchmark, to the best ability, the real-time and planning horizon assessments to ensure consistency in the planning process.” To meet the goal of consistency in the planning process, the TPITF recommends the building of a common base reliability model that will be used for all SPP planning processes including Transmission Service and Generation Interconnection as well as the ITP. This base reliability model will also serve as the base model for the TPL Steady State assessment. The TPITF also recommends the TWG select the TPL sensitivity case from the CBA Reliability model set.

Current State

The set of models currently used in the SPP planning processes are listed below. The ITPNT Reliability and the TPL Steady State models use the MDWG Powerflow model as their base model.

<table>
<thead>
<tr>
<th>Description</th>
<th>Year 1</th>
<th>Year 2</th>
<th>Year 5</th>
<th>Year 10</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>ITPNT Reliability</td>
<td>-------</td>
<td>Scenario 0: ITPNT SP &amp; WP</td>
<td>Scenario 0: ITPNT SP &amp; WP</td>
<td>-------</td>
<td>15</td>
</tr>
<tr>
<td>ITP10 Economic</td>
<td>-------</td>
<td>-------</td>
<td>Futures (1/2/3): 8760 hrs</td>
<td>Futures (1/2/3): 8760 hrs</td>
<td>6</td>
</tr>
<tr>
<td>TPL - Steady State Assessment</td>
<td>R2.1.1 Y-1 Peak: MDWG S (base) &amp; ITPNT SP5 (sensitivity)</td>
<td>R2.1.1 Y-1 Off-Peak: MDWG L (base) &amp; ITPNT L5 (sensitivity)</td>
<td>R2.1.1 Y-5 Peak: MDWG (base) &amp; ITPNT SP5 (sensitivity)</td>
<td>R2.2.1 Y-10 Peak: MDWG S (base)</td>
<td>4</td>
</tr>
<tr>
<td>TPL - Series Short Circuit</td>
<td>S Max Fault</td>
<td></td>
<td></td>
<td></td>
<td>1</td>
</tr>
</tbody>
</table>

3 Cases are defined as: SP (summer peak), WP (winter peak), L (light load), and S (summer)
The current model build schedule can be summarized as shown below.

**MDWG Models**

The final MDWG Powerflow and Short Circuit models are typically scheduled to post simultaneously. This posting is usually scheduled for the 1st quarter of each new calendar year in the February timeframe.

Work on the MDWG Dynamics model is performed prior to the posting of the MDWG Powerflow model. The effort consists of building the DYRE files, incorporating topology updates submitted by members, and mitigating errors found in the model. Following the posting of the MDWG Powerflow model, the Dynamics model build continues, lasting approximately six months in duration.

**ITP Models**

The ITPNT Reliability models are built using the same database (MOD) as the MDWG Powerflow models. As with the Dynamics model build, work on the ITPNT Reliability model is performed prior to the posting of the final MDWG Powerflow models. This consists of modeling topology updates to reflect only existing and approved facilities, transactions, and updates to generation dispatch. Following the posting of the MDWG Powerflow models, the ITPNT Reliability model build will continue for approximately three months in duration.

The CBA Reliability model uses the initial pass of the ITPNT Scenario 0 Reliability model as its topology base. ITP10 economic data is utilized to provide seasonal generation economics, wind profiles, and hydro profiles. Each pass of the CBA Reliability model is dispatched based on a security constrained economic dispatch (SCED) and provided for member review.

The ITP10 models are based on the 10-year ITPNT Scenario 0, summer peak model. It incorporates the Scenario’s topology for base load and generation. This topology is the base of the PROMOD economic model. The next steps in the economic model build process are the load and generation reviews where members can confirm or adjust their load, add economic data to the existing generation, and confirm or adjust the resource name plate values used to create the 10-year ITPNT model. In order to meet the renewable capacity and/or energy requirements, SPP Staff will evaluate if all the requirements are met and if they are not met, add additional renewable resources to the model. It is also necessary to meet the required capacity margin for each zone. To achieve that, it is necessary to develop a resource plan where conventional and renewable prototypes are considered to determine needed and more economically viable additions. Resources added to the economic model are then sited throughout the SPP system. The last step in the model build process is to perform a constraint assessment to verify how the models behave when the system is constrained and to identify any new flowgates that should be monitored. The number of models is dependent on the amount of Futures included in the ITP10 study scope. Members are responsible for the review and approval of the model sets, and provide vital feedback during each of the model build steps mentioned above.
TPITF Issues Related to Current Modeling Practices

The TPITF identified a number of issues related to the planning models and their corresponding builds that inhibit the efficiency, consistency, and accuracy of the currently constructed model sets. While the complete issues list can be found in Appendix C, issues related to the models are summarized as follows:

- Models are not constructed in a consistent manner across the planning processes. Models are fundamentally different between the processes.
- Separate model builds for the different planning processes place additional burdens on members to submit and review data several times throughout the year.
- The models are not indicative of what is happening in real-time under the new Integrated Marketplace. Market and Operations feedback should be reflected in the model development process.

Desired State

The table below lists the proposed model sets for the TPITF recommended ITP planning cycle. These models differ significantly from the planning model sets currently built and are described in further detail below. The base reliability model listed and described below will become the base model for all of SPP’s planning processes including Transmission Service, Generation Interconnection, and the TPL Steady State compliance study. This will address concerns Stakeholders have expressed over model consistency between the planning processes.

<table>
<thead>
<tr>
<th>Description</th>
<th>Year 2</th>
<th>Year 5</th>
<th>Year 10</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability: CBA</td>
<td>One Future Coincident Peak 4On/Off-Peak (2)</td>
<td>Up to Three Futures Coincident Peak On/Off-Peak (6)</td>
<td>Up to Three Futures Coincident Peak On/Off-Peak (6)</td>
<td>14</td>
</tr>
<tr>
<td>(TPL Sensitivity Case)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reliability: Base Scenario</td>
<td>Summer Winter Light Load Non-coincident Peak (3)</td>
<td>Summer Winter Light Load Non-coincident Peak (3)</td>
<td>Summer Winter Light Load Non-coincident Peak (3)</td>
<td>9</td>
</tr>
<tr>
<td>TPL: Powerflow</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Economic</td>
<td>One Future Coincident Peak 8760 (1)</td>
<td>Up to Three Futures Coincident Peak 8760 (3)</td>
<td>Up to Three Futures Coincident Peak 8760 (3)</td>
<td>7</td>
</tr>
</tbody>
</table>

The proposed model build schedule is listed below. In order to meet the model build timeline necessary to facilitate the 12-month ITP assessment window, the ITP Reliability model will be built in parallel with the MDWG Powerflow and Short Circuit models. With this change, the TPITF recognizes the need to collect the data required to build the ITP Reliability model earlier in the process than it is requested today. The current MDWG model build schedule will be leveraged to govern the collection of required data. Leveraging the MDWG model build schedule will address member concerns with multiple data review and submittal windows found across the separate model builds in the planning processes.

\(^4\) NERC defines On-Peak as “...periods of higher electrical demand.” and Off-Peak as “...periods of lower electrical demand.”
Required data will be requested, submitted, and reviewed on the front-end of the model build process, thereby eliminating the multi-process burdens currently experienced by members.

Efficiencies implemented in the Economic model build process will also help facilitate the 12-month ITP assessment window by reducing the build time to a little over six months.

The TPITF recommends the structure of the ITP model sets to consist of the following:

- Base Reliability Model
- Economic Model
- CBA Reliability Model

**Base Reliability Model**

At least one scenario powerflow model will be required in order to meet the reliability planning requirements for the SPP region. This base reliability model will be developed as an indicative representation of how entities within SPP responsible for serving network load would serve network load utilizing network resources only. This model would consist of non-coincident peak load forecasts, assumed long-term firm transmission service usage levels, and expected conventional and renewable resource output levels. The TPITF recommends the modeling of renewable facilities’ output at each facility’s highest summer on-peak hour, hours 15:00-19:00, within the last three years per facility and off-peak and light load at 100% of firm service. For new renewable resources, the average of facility peaks within the new resources’ areas will be used to model the resources’ outputs.

The Year 2, 5, and 10 base reliability model set utilized for regional and sub-regional reliability planning will also be utilized as the base model(s) for long-term firm transmission service request studies. However, these base model(s) will be adjusted as necessary to appropriately analyze and integrate transmission service requests consistent with the SPP Tariff provisions and business practices that govern the process.

The base model set will not include the CBA model, but instead only the base scenario in which each entity’s firm resources and transactions are dispatched to serve each entity’s network load. As a result, upgrades resulting from the transmission service process should represent those necessary to support the firm transmission service requests that were added to the base model for study, also ensuring transmission facilities are not approved to support non-firm market transactions. This should also maintain consistency between the firm system capacity utilized to honor the transmission service and the firm system capacity that may be utilized as Auction Revenue Rights (ARRs) and ultimately Transmission Congestion Rights (TCRs) in the TCR market.

The Year 2, 5, and 10 base reliability model sets utilized for regional and sub-regional reliability planning will also be utilized as the base model sets for generator interconnection request studies. However, the
base model set will be adjusted as necessary to execute the study of generator interconnection service requests consistent with the tariff provisions and business practices that govern the process.

**Economic Model**

Economic models will be developed to identify and assess solutions to the public policy and economic needs of the SPP system. Economic models will be developed for three study years (Years 2, 5, and 10). A single economic model will be developed for the one future in Year 2. It is assumed that multiple future cases are not necessary for Year 2 due to the limited uncertainty in policy or other factors impacting the system that could be implemented in such a short time frame. Up to three economic models will be developed for the reference case future in Years 5 and 10. As a result, up to seven total economic models may be developed to support economic assessments.

The current economic and policy study processes for the ITP10 call for needs assessments for Year 10 only. The proposal above will add additional economic and policy needs assessments for Years 2 and 5.

**CBA Reliability Model**

The CBA powerflow models will be developed as an indicative representation of how load would be served in the SPP Integrated Marketplace. This CBA model will be built from PROMOD output and will consist of coincident peak load forecasts for the SPP region and the security constrained commitment and dispatch of both firm and non-firm generating resources derived from economic planning models. Interchange between SPP and Tier 1 will be determined based on price differentials that may include hurdle rates as developed with the existing economic process. The TPITF recommends the TWG select the TPL sensitivity case from the CBA Reliability model set.

**TPL Assessment Models**

The Year 2, 5, and 10 base reliability model sets utilized for regional and sub-regional reliability planning will be utilized as the base model sets for the TPL Steady State assessment. As noted above, the CBA powerflow model set will be used for the selection of the sensitivity case required in addition to the base case model for TPL compliance. Not all of the reliability or CBA models will be used, only the models necessary to meet compliance with TPL-001-4.

The MDWG short circuit model with all planned generation and transmission facilities in service is represented with the following additional requirements:

- Place all available facilities in-service:
  - Generation
  - Transmission lines (Out for maintenance)
  - Transformers
  - Buses
- Flat – classical fault analysis conditions

This model set establishes category P0 as the normal System condition and defines the models that will be used for the short circuit analyses to comply with requirement TPL-001-4 R2.3 as the Maximum Fault Year 2 Summer.
Holistic Planning Process

Purpose

The TPITF envisions an efficient and effective planning process in which all SPP regional Planning assessments are coordinated to produce transmission expansion plans that will optimize the use of the SPP transmission system while maintaining reliability.

Creating efficiencies in the planning process by synchronizing processes and coordinating study findings will be the building blocks by which a planning process will be constructed that will address reliability, economics, public policy, and regulatory compliance needs over the 10-year planning cycle.

Aligning planning processes along with SPP Operations will facilitate the sharing of the most accurate information and data between studies and will allow the ITP process the opportunity to address issues that may have not been identified in the Generation Interconnection and Transmission Service Study processes but that are observed within the real-time environment.

Current State

TPITF Issues with Parallel Planning Processes

The TPITF identified a number of issues related to the various aspects of the planning process. While the complete issues list can be found in Appendix C, issues related to the planning process are summarized as follows:

- Chronic operational issues not being addressed in the long-term planning process.
- Project evaluation and selection does not consider all factors necessary for comprehensive engineering economic analysis. Planning horizon assessments do not appropriately account for the impacts of real-time markets.
- Planning process has no regional funding mechanism for projects necessary to mitigate higher depth contingency planning required for NERC compliance.
- Planning processes are disconnected and do not inform one another.

Desired State

The TPITF proposes a regional planning process built to leverage knowledge of the transmission system’s reliability, public policy, compliance, and economic needs, as well as generation interconnection and transmission service request impacts in order to develop a more cost-effective transmission portfolio for a 10-year planning horizon. The TPITF believes this will be enabled by utilizing a common set of foundational modeling assumptions as the starting point for all planning studies within the planning cycle as discussed in the Common Planning Model section of this whitepaper. The staging of the model builds for all reliability, public policy, compliance, and economic studies will be determined to produce a single needs assessment for the 10-year planning horizon. System needs resulting from generation interconnection and transmission service requests will be identified within the currently established timelines for those processes. However, the evaluation of transmission service needs and associated projects will be coordinated with those identified in the 10-year horizon regional planning process to facilitate continuity in the overall transmission expansion plan.
Reliability and Compliance Assessments

Reliability and compliance needs will be determined based on NERC Standards, SPP Planning Criteria, and Sub-Regional Planning Criteria of individual SPP members. The reliability needs will be produced from the base reliability and CBA reliability models for Years 2, 5, and 10 as described in further detail in the Common Planning Model section of this whitepaper. The base reliability needs will represent potential criteria violations based on a model set that utilizes only firm resources and firm transactions to serve non-coincident network load on an individual Balancing Authority (BA) by individual BA basis. The CBA reliability needs will represent potential criteria violations based on a model set that utilizes both firm and non-firm resources with a market dispatch to serve SPP coincident network load.

Compliance needs will be produced from the TPL base reliability and Short Circuit models for Years 2, 5, and 10 as described in further detail in the Common Planning Model section. Compliance needs that may be considered for NTCs will represent TPL-001-4 contingencies that do not allow for non-consequential load loss or interruption of firm transmission service (P0-P3). Mitigations, at a minimum, will be developed by SPP Staff or the applicable TP for TPL-001-4 contingencies that do allow for non-consequential load loss or interruption of firm transmission service (P4-P7). Planning Event descriptions are listed in Appendix A.

After reviewing the TPL stability study process, the TPITF chose not to include the study in the ITP planning process. Factors considered were the historical lack of issues identified in the process that would require transmission projects, the use of the proposed ITP models, Order 1000 implications, and the general consensus within the TPITF that inclusion of the assessment does not provide any tangible benefit to the study that would justify the potential resource, cost, and schedule impacts its inclusion would have on the ITP planning process. The remaining TPL Steady State events will be handled along with the stability process outside of the ITP process.

Public Policy Assessments

Public policy needs are considered to be any system deficiency that prohibits attaining renewable energy mandates or goals in the economic model runs for each Future in Years 2, 5, and 10 due to renewable energy curtailments caused by transmission congestion.

Economic Assessments

Economic needs will be determined based on the adverse impact of congestion on the cost of energy production, energy purchases, and sales for the SPP region. Economic needs will be produced from the economic models for Years 2, 5, and 10 described in further detail in the Common Planning Model section. Economic needs will represent a list of the most congested flowgates in the economic model runs for each Future in Years 2, 5, and 10.

Generation Interconnection Request Assessments

Generation interconnection needs will be determined based on NERC Criteria, SPP Planning Criteria, and Sub-Regional Planning Criteria of individual SPP members. The reliability needs will be produced from the models that begin with the base reliability models for Years 2, 5, and 10 as described in further detail in the Common Planning Model section. All generation interconnection requests will be added to the models. The reliability needs identified will represent potential criteria violations due to the interconnection of the generation determined from the powerflow, dynamic stability, and short circuit assessments. For the powerflow assessment, transmission reinforcement is required for violations that meet the generator interconnection criteria for impacts to the constraints for the contingencies specified in the ITP process. For the stability analysis, unstable conditions will be addressed for
transmission reinforcement for contingencies specified in the dynamic stability assessment for TPL-001-4 contingencies equivalent to P0, P1, P2.1-2.3, P4, and P5 as identified by SPP and the Transmission Owners. Higher depth contingencies (P6-P7) will be evaluated as necessary for the location of the generation for mitigations. For the short circuit assessment, transmission reinforcement will be required for a scenario with all generation and all transmission elements in service (P0).

Transmission Service Request Assessments

Transmission service needs will be determined based on NERC Criteria and SPP Planning Criteria and will be produced from the base reliability models for Years 2, 5, and 10 described in further detail in the Common Planning Model section. Transmission service needs will represent transmission system overloads caused or impacted by the requested transfer(s).

Network Integration Transmission Service (NITS) requests are modeled as generation to load transfers in addition to generation to generation transfers. This is done because NITS is a request to serve network load with the new designated network resource, and the impacts on the transmission system are determined accordingly. Point-To-Point transmission service requests are modeled as generation to generation transfers. Generation to generation transfers are accomplished by developing a post-transfer case for comparison by dispatching the requested source and redispaching the requested sink.

Operational Assessments

The determination of operational needs will be based on chronic operational issues with a significant financial or reliability impact identified in the operation of the integrated marketplace. SPP Operations observes a more diverse range of system operating scenarios that may not be feasible to effectively simulate in the planning environment. As a result, certain reliability and economic needs that are seen with relative frequency in the real time operations may not be identified in the long term planning process. Further, the long term planning process currently does not have a mechanism to address these issues with NTCs for new projects. The TPI TF recommends the following process for incorporating operational issues into the planning process.

SPP Operations Staff will work with the appropriate Stakeholder groups to develop criteria around the definition and designation of chronic operational issues that should be evaluated in the planning process. Once the criteria for identifying operational issues has been established, SPP Operations will provide SPP Planning with a list of economic and reliability operational needs along with the historical context for each issue. For reliability operational needs, historical context may consist of data such as the frequency and duration of occurrences of the reliability events as well as related outage information along with other types of supporting information. For economic operational needs, historical context may consist of data such as congestion or uplifted costs associated with the issue.

Upon establishment of the ITP portfolio of proposed transmission projects, these projects will be tested as solutions to the reliability and economic operational needs using operational models that captured actual occurrences of the needs. These operational models will be approved by the applicable SPP stakeholder working groups to ensure consistency with the criteria established to designate the operational needs as chronic, rather than infrequent system needs. For those operational needs that are not mitigated by the proposed set of projects, SPP Staff will work with the affected incumbent transmission owners to develop candidate projects to address the needs. The candidate projects and associated justification will be presented to the TWG, ESWG, and ORWG for their review and endorsement. The list of endorsed projects will be submitted to MOPC and the SPP BOD for approval at the next meeting of each of the groups following the approval of the ITP project portfolio.
Seams

In order to ensure a robust and effective regional planning process, the evaluation of transmission system reliability, economic, and public policy needs must also account for the opportunity to jointly develop beneficial projects with SPP’s neighbors. Interregional planning processes alone may not be sufficient to adequately address these needs along SPP’s seams. SPP’s regional planning processes should help to facilitate interregional planning where possible. SPP engages in interregional planning activities pursuant to FERC Order 1000 with MISO and the Southeastern Regional Transmission Planning (SERTP) group. Additionally, SPP has Joint Operating Agreements (JOAs) with various other utilities that govern periodic or ad-hoc joint planning processes.

Because many of the same Staff and Stakeholder resources are involved in both SPP regional and interregional planning activities, coordination between the various processes is vital to ensure consistency and efficiency. Each of the process changes envisioned in this recommendations whitepaper should be evaluated for opportunities to align or leverage similar activities occurring in interregional processes. Additional recommendations could also be made for SPP Staff to propose appropriate changes to applicable agreements with neighboring entities.

As described in the Common Planning Model section, SPP’s regional model development attempts to model neighboring regions consistent with how those neighboring regions model themselves in their respective regional planning processes. During the construction of each regional planning model, efforts will be made to acquire the necessary modeling information from neighboring entities. This coordination process is best facilitated where SPP and neighboring modeling schedules are closely aligned. Where appropriate, information from recent interregional planning processes will be leveraged.

SPP’s regional planning processes should also facilitate the identification and resolution of reliability, economic, and public policy needs along the seams. This consideration of needs along SPP’s seams will include coordination with SPP markets and operations to evaluate issues impacting neighboring utilities. The development of a process to consider the impact of Market-to-Market transactions may provide valuable input into the identification of seams issues and potential mitigations.

Solution Development

All reliability, compliance, public policy, and economic needs, as described above, that could result in NTCs will be aggregated and posted publicly to initiate a single Detailed Project Proposal (DPP) window. Compliance needs such as TPL-001-4 P4-P7 events as well as generation interconnection and transmission service request needs will be addressed outside of the DPP window in compliance with the timelines specified under the existing processes. SPP Staff will evaluate DPPs as well as Staff solutions to develop the most cost-effective solutions to all reliability, public policy, compliance, and economic needs. This will be accomplished by evaluating the patterns and drivers of system needs over the full 10-year planning horizon. Also, synergies of candidate solutions will be analyzed and leveraged as appropriate. For instance, the viability of deferring or displacing reliability, compliance, or public policy solutions with projects that preserve those attributes but also produce economic benefits will be evaluated for the full 10-year planning horizon.

Transmission system needs that are consistent across the full planning horizon will be addressed with cost-effective long-term solutions. When required, short-term mitigations will be sought, selected, and implemented while maintaining system reliability. Reliability, compliance, public policy, and economic needs that are identified in the early portion of the 10-year planning horizon, but not identified in the later portion will be evaluated in detail to determine the anticipated changes in system conditions or...
topology that are mitigating the need in the long-term. The system changes that mitigate transmission system needs in the long-term will be documented and the short-term need will be evaluated with the use of short-term mitigations or least-cost solutions until the need is permanently displaced with the longer-term solution. Reliability, compliance, public policy, and economic needs that are identified in the latter portion of the 10-year planning horizon, but are not identified in the early portion will be addressed with the use of cost-effective long-term transmission solutions.

Solutions that are evaluated in the 10-year regional planning process will also be evaluated as possible candidate solutions to needs identified in the generation interconnection and transmission service request evaluation processes. Identical needs occurring during identical time periods that are identified in both the 10-year regional planning process and the applicable service process will be evaluated using the 10-year regional planning process solution(s). Identical needs that occur in an earlier time period in the 10-year regional planning process than in the applicable service process will be evaluated using the 10-year regional planning process solution. Identical needs that occur in the 10-year regional planning process after they occur in the applicable service process will be evaluated using acceleration of the 10-year regional planning process solution, and costs will be allocated consistent with existing cost allocation methodologies under the SPP Tariff. For all other needs that are identified in the generation interconnection and transmission service request processes, the least-cost solution necessary to accommodate the service request will be selected.

Solutions for compliance needs such as TPL-001-4 P4-P7 events will be developed through coordination between SPP Staff and SPP Transmission Owners. These solutions will be considered corrective action plans that may or may not include transmission expansion.
Staff/Stakeholder Accountability

Current State
The ITP process requires a significant amount of collaboration between SPP Staff and SPP Stakeholders in order to produce the required deliverables of the study. SPP Stakeholders are responsible for establishing the scope of the studies and also providing guidance for the methodologies to be used in the studies. Further, SPP Stakeholders are responsible for providing the data necessary to implement the scope and methodologies and to also review study data and results to certify quality.

SPP Staff is responsible for the facilitation of the Stakeholder process and implementation of the study scope. These efforts include notifying SPP Stakeholders of tariff and other governing document requirements to support study scope development, identification and solicitation of data necessary to implement the scope, recommendations for methodologies to efficiently execute the scope, and any other general support necessary to implement the study scope. Staff is also responsible for developing project schedules that determine the time allotted to accomplish each aspect of the study scope and also the responsible party for those aspects of the scope.

The data exchange and data review deadlines in these schedules are often breached in the current ITP process. This has led to project schedule mitigations actions that have proven to be inefficient and costly. These project schedule mitigations may reduce time for Staff to perform study work and also reduce Stakeholder review time and threatens Stakeholder satisfaction and the overall quality of the study.

Desired State
The TPITF recommendations for reforms to the planning process, specifically the inclusion of TPL analysis in the study and the annual planning cycle, will increase the criticality of coordination between SPP Stakeholders and Staff. SPP Stakeholders are responsible for establishing the scope of the studies and also providing guidance for the methodologies to be used in the studies. Further, Stakeholders are responsible for providing the data necessary to implement the scope and methodologies and to also review study data and results to certify quality. SPP Stakeholders and Staff will implement an accountability assurance program that consists of mechanisms designed to promote timely data exchanges, reviews, and approvals within the transmission planning process. The program will identify all entities responsible for providing data to the process and also include the identification of actions that will be taken in the absence of timely data exchanges, reviews, and approvals. The program will also describe options available to any entities that would like to submit study data after the data exchange deadlines or request changes to data after the data review deadlines.

SPP Staff will develop a project schedule in parallel with the development of the scope of each study. This schedule will identify the timing, duration, and responsible parties for all data exchanges, data reviews, and approvals required to complete the ITP study. SPP Staff will coordinate with Stakeholders in the development of this schedule and formally vet the final schedule with Stakeholders within one month of the completion of the study scope and assumptions document. Each member company will identify a single point of contact for their company that will be responsible for addressing all data required to support the modeling process. For each data exchange identified in the study schedule, applicable SPP working groups and Staff will agree upon the data that will be used as a proxy for Stakeholder supplied data to keep the process moving forward in the event the data is not supplied by the data exchange deadline. If data reviews are not conducted by the associated schedule deadlines, the data will be assumed to be appropriate and the study will move forward as scheduled.
conclusion of each data exchange window, but no less than each quarter, SPP Staff will provide a report card to the MOPC listing any deadlines breached by SPP Stakeholders or Staff.

Any entity that does not meet prescribed data exchange, review, or approval deadlines and wants to add or change data used in the study may make a request for a waiver of the deadline to the MOPC. SPP Staff will provide the MOPC with the project schedule impacts, schedule mitigation plans, and an estimate of any costs associated with accommodating the waiver to support the MOPC decision making process. Upon approval of the waiver and associated schedule mitigations and costs, SPP Staff will incorporate the Stakeholder data into the planning process. In the event the waiver is not approved, SPP Staff will make no changes to the study process and will continue moving forward with the current study schedule.
Transition and Implementation

The TPITF recommends a transition to the new 2019 ITP planning process starting in September 2017 with the ITP model builds and scope development leading to the initial ITP planning assessment that will be completed in July of 2019. The transition to the new planning process will require two preliminary steps. First, the current planning cycle will need to be completed. Second, SPP Stakeholders and Staff will need to implement all changes necessary to allow the new process to move forward. These changes will include, but are not limited to modifications to the SPP tariff and other appropriate governing documents, establishment of the details of the new processes and procedures for the new planning study by the applicable SPP working groups, and the procurement of resources and tools necessary to implement the process. The chart below illustrates the transition activities, projected durations, and the timing of the first two planning processes under the new ITP process and is discussed in further detail below.

<table>
<thead>
<tr>
<th>Year</th>
<th>2016</th>
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<th>2018</th>
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**Current Planning Cycle Completion**

The current ITP planning cycle has two remaining studies, the 2017 ITP10 and the 2017 ITPNT. The 2017 ITP10 is scheduled to be completed in January 2017. The 2017 ITPNT is scheduled to begin in April 2016 and be completed in April 2017. The next ITP planning cycle under the current process would begin with an ITP20 assessment that commences in 2017, as well as the 2018 ITPNT that would begin in April 2017 and end in April 2018.

While the TPITF believes the 2018 ITPNT assessment is necessary to for continued reliability planning during the transition, the TPITF does not believe an ITP20 study should begin in 2017. Instead, the TPITF believes SPP Stakeholder and Staff resources would be better utilized by focusing their efforts on initiatives necessary to facilitate the successful implementation of the new ITP Planning process.
TPITF recommends the suspension of the ITP20 for 2017. SPP will need to make a FERC filing to accomplish this recommended suspension. If the study is required by the SPP BOD, the TPITF recommends outsourcing the performance of the study to free up the resources necessary for implementation of the new planning process.

There will be three more TPL assessments performed under the current processes, prior to the inclusion of TPL power flow and short circuit assessments into the new ITP planning process. These assessments are the 2016, 2017, and 2018 TPL assessments and will be completed in December 2016, December 2017, and December 2018 respectively. The 2019 TPL stability assessment will commence in the latter half of 2018 rather than January of 2019 to align with the 2019 ITP assessment timeframe. In essence, the TPL assessments will be performed twice in 2018 in order to facilitate alignment with and inclusion in the 2019 ITP assessment and meet annual NERC posting requirements.

Implementation Preparation

The TPITF will provide a final set of recommendations to the MOPC, SPC, and SPP BOD in July 2016 for approval. At that point, it is the Task Force’s intent to forward the approved recommendations to the appropriate Stakeholder groups for process development and implementation. During the timeframe between the 2016 April and July MOPC/SPP Board cycle, the TPITF will work with impacted Stakeholder groups to develop timelines for the development, review, and implementation of the changes to the planning process. This information will be used to develop more detailed schedules for the transition to the new process. The TPITF will also work with SPP Staff and Stakeholders to determine potential resource and other budgetary impacts of the recommended process improvements. Workshops will be held to inform and educate Stakeholders on the proposed improvements in order to present a clear and vetted set of final recommendations in July 2016.

The TPITF will also present an implementation plan that will outline the deliverables and timelines required by Stakeholder groups to meet the start date of the new ITP planning process. The plan will also describe the changes to governing documents needed to facilitate the move to a holistic planning process. The TPITF foresees major involvement from SPP Staff, TWG, ESWG, ORWG, RCWG, and RTWG with the coordination of the transition to the new planning process along with the work necessary to update the ITP Manual, SPP Tariff, SPP business practices, and SPP Criteria.
Recommendations

Annual Planning Cycle
The TPITF recommends the reduction of the three-year Integrated Transmission Plan assessment cycle to an annual planning cycle that will produce a 10-year transmission expansion plan each year.

- Remove the ITP20 Assessment from the three-year ITP cycle. Place the performance of the 20-year study under the guidance of the SPC to be performed no less than once every five years unless directed by the SPP Board.
- Combine the Near Term and 10-year Assessments into a single planning study.

Standardized ITP Study Scope
The TPITF recommends standardizing ITP study scope items and the development of a streamlined assumptions document.

- Standardize scope items and incorporate into the ITP Manual.
- Place the ITP Manual under SPP Planning Protocols.
- Assumptions document for approval items. Identify items that will require up-front approval (futures, fuel prices, etc.).
- Utilize SPP’s RR process for changes to standard scope items.

Common Planning Model
The TPITF recommends the development of a single, base reliability powerflow model that will be used for all SPP planning processes including Transmission Service and Generation Interconnection as well as the TPL Steady State assessment.

- One base reliability model for all planning processes including TPL Steady State assessment replacing the Scenario 0 and 5 models with an as-expected model.
- Model renewable facilities’ output at each facility’s highest summer on-peak hour, hours 15:00-19:00, within the last three years per facility and off-peak and light load at 100% of firm service. For new renewable resources, the average of facility peaks within the new resources’ areas will be used to model the resources’ outputs.

Holistic Planning Process
The TPITF recommends combining the ITPNT, ITP10, and the TPL Steady State and Short Circuit assessments into a single, 10-year ITP study that will produce an integrated transmission expansion plan addressing reliability, economic, policy, and compliance needs in Years 2, 5, and 10.

- Issue NTCs for all needs in Years 2, 5, and 10.
- Develop a process for identifying and incorporating chronic operational issues into the ITP process.

SPP Staff/Stakeholder Accountability
The TPITF recommends development of an accountability assurance program that consists of mechanisms designed to promote timely data exchanges, reviews, and approvals within the transmission planning process.
• Formal MOPC/SPP BOD reporting structure for communicating staff/stakeholder non-compliance with deadlines.

Transition and Implementation

The TPITF recommends a transition to the new 2019 ITP planning process starting in September 2017 with the ITP model builds and scope development leading to the initial ITP planning assessment that will be completed in July of 2019.

• Suspension of the ITP20 for 2017. If the study is required by the SPP BOD, the TPITF recommends outsourcing the performance of the study to free up the resources necessary for implementation.
Appendix A: Planning Events

P0

- N-0, No Contingencies

P1

- N-1, Single Contingency
- Must use footnote 12 to have Non-consequential load loss or curtailment of Firm Transmission service
- Steady State
  - Use auto N-1 to capture all possible combinations
- Stability
  - Use Fast Fault Scan to determine events for study

P2

- N-1, Single Contingency
- Steady State
  - TP submitted 230 kV and above
  - Captured in auto N-1
  - Script written to capture opening line section without fault
- Stability
  - Use Fast Fault Scan to determine events for study
  - TP submitted 230 kV and above

P3

- G-1, N-1, Multiple Contingency
- Must use footnote 12 to have Non-consequential load loss or curtailment of Firm Transmission service
- Steady State
  - First contingent element will be a generator
  - System Adjustments are made
  - Second contingent element will be in same area as first
- Stability
  - Use Fast Fault Scan to determine events for study
  - TP submitted 230 kV and above

P4

- N-k + stuck breaker, Multiple Contingency
- Can use Non-consequential load loss and curtailment of Firm Transmission service for HV (<300kV)
- Steady State
  - TP submitted 230 kV and above
- Stability
  - TP submitted 230 kV and above

P5

- N-k + non-redundant relay failure, Multiple Contingency
- Can use Non-consequential load loss and curtailment of Firm Transmission service for HV (<300kV)
- Steady State
  - TP submitted 230 kV and above
- Stability
Appendix A: Planning Events

P6

- N-1-1, Multiple Contingency
  - No Generator contingencies
  - Can use Non-consequential load loss and curtailment of Firm Transmission service
- Steady State
  - First contingent element will not be a generator
  - System Adjustments are made
  - Second contingent element will be in same area as first
- Stability
  - Use Fast Fault Scan to determine events for study
  - TP submitted 230 kV and above

P7

- N-2, Multiple Contingency
  - Common Structure or loss of a bipolar DC line
  - Can use Non-consequential load loss and curtailment of Firm Transmission service
- Steady State
  - TP will provide to PC
- Stability
  - TP will provide to PC

Extreme Events

- N-k +, Multiple Contingency
- Steady State
  - TP will provide to PC
- Stability
  - TP will provide to PC
## Appendix B: Proposed ITP Planning Process Timeline

![ITP Planning Process Timeline Diagram]
## Appendix C: TPITF Issues List

<table>
<thead>
<tr>
<th>TPITF Issue</th>
<th>Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Build time - A year to develop model is too long, and leaves only 30 days to use it</td>
<td>Common Planning Model</td>
</tr>
<tr>
<td>Build time - Need some models to last longer than a year to reduce burden on member staffs</td>
<td>Common Planning Model</td>
</tr>
<tr>
<td>Build time - Issues show up with little time to address (load/gen input issues, inconsistent assumptions between processes, etc.)</td>
<td>Common Planning Model</td>
</tr>
<tr>
<td>Data review - Schedule and process, especially for economic models, could use better documentation and structure</td>
<td>Standardized Scope</td>
</tr>
<tr>
<td>Bridge model - Need a 7-year-out model to bridge gaps between ITP-NT and ITP-10 (NT &amp; 10 are fundamentally different models)</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Seams - Study process and/or inputs hampered by lack of relationship between interregional and intraregional models</td>
<td>Seams Discussion</td>
</tr>
<tr>
<td>Seams - Planning models don't reflect needs on the seams</td>
<td>Seams Discussion</td>
</tr>
<tr>
<td>Load forecasting - Inconsistency across entities, combined with no verification mechanisms, leads to distrust</td>
<td>TWG Consideration</td>
</tr>
<tr>
<td>Load forecasting - Need a consistent methodology for including load forecasting in the SPP model</td>
<td>TWG Consideration</td>
</tr>
<tr>
<td>Load/generation - Minimize potential for gaming by having unit dispatch for models come from SPP under CBA model</td>
<td>Review Completed</td>
</tr>
<tr>
<td>Market realities - Market feedback should be reflected within model development (including generation dispatch, SCED)</td>
<td>Common Planning Model/Holistic Planning Process</td>
</tr>
<tr>
<td>Market realities - Inconsistency with how markets work, e.g., models rely on block dispatch vs. market dispatch</td>
<td>Common Planning Model/Holistic Planning Process</td>
</tr>
<tr>
<td>Market realities - Reflection of CBA dispatch needs to become more prevalent</td>
<td>Common Planning Model/Holistic Planning Process</td>
</tr>
<tr>
<td>Market realities - Inconsistencies in modeling delivery between evaluations, e.g., between studies like ITP-NT and GI</td>
<td>Common Planning Model</td>
</tr>
<tr>
<td>TPITF Issue</td>
<td>Classification</td>
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<tr>
<td>Is MOD the right tool? Other alternatives?</td>
<td>Review Completed</td>
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<tr>
<td>Data Submittal - SPP does not get enough accurate data on the first pass; should be close by second pass</td>
<td>Staff/Stakeholder Accountability</td>
</tr>
<tr>
<td>Data Submittal - Need more enforceable deadlines for meeting set submission timelines</td>
<td>Staff/Stakeholder Accountability</td>
</tr>
<tr>
<td>Data Submittal - Data is coming from planners; not operations or markets</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Corrections - Sometimes make the same corrections over and over (lost productivity); affects confidence in models</td>
<td>Common Planning Model</td>
</tr>
<tr>
<td>Corrections - Known problems such as flowgate issues don't get fixed in between models</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Corrections - Are we address flowgate and other issues identified in the state-of-the-market report?</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Gaps - Disconnect between SPP planning and operations results in issues making it into model (MOD-33 may fix?)</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Gaps - Models inconsistent among various processes (ITP, GI, Agg, TS) and between RTOs</td>
<td>Common Planning Model</td>
</tr>
<tr>
<td>Gaps - Experiencing operational issues that didn't show up in planning models</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Gaps - No feedback loop from member IRPs to the transmission planning model</td>
<td>Standardized Scope/Accountability</td>
</tr>
<tr>
<td>Gaps - Reliability models in ITP-10 may not be sufficient; may need to be more similar to ITP-NT model</td>
<td>Common Planning Model</td>
</tr>
<tr>
<td>Gaps - Stakeholders not consistently informed of material changes in models when request window is still open</td>
<td>Staff/Stakeholder Accountability</td>
</tr>
<tr>
<td>Gaps - Validation issues result from ProMod tool automatically doing 6-month public data updates; can address by notifying vendor</td>
<td>ESWG Consideration</td>
</tr>
<tr>
<td>Automation - Members need more automation to help with their data reviews</td>
<td>Staff Consideration</td>
</tr>
<tr>
<td>Automation - Improve MOD tool for consistency and reduced build time</td>
<td>Review Completed</td>
</tr>
<tr>
<td>Uncertainty of and lack of validation of data in the models</td>
<td>Staff/Stakeholder Accountability</td>
</tr>
<tr>
<td>TPITF Issue</td>
<td>Classification</td>
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<tr>
<td>---------------------------------------------------------------------------</td>
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</tr>
<tr>
<td>Experience delays in receiving model from members</td>
<td>Staff/Stakeholder Accountability</td>
</tr>
<tr>
<td>Duplication of effort due to lack of standardization of data</td>
<td>Common Planning Model</td>
</tr>
<tr>
<td>People don't trust the data</td>
<td>Staff/Stakeholder Accountability</td>
</tr>
<tr>
<td>Disconnect between submitters and users</td>
<td>Single Point of Contact</td>
</tr>
<tr>
<td>Notices to Construct - Lack clarity around what qualifies for NTCs</td>
<td>Standardized Scope</td>
</tr>
<tr>
<td>Wind - Need to improve modeling of wind farms that have interconnection but no transmission service</td>
<td>Standardized Scope</td>
</tr>
<tr>
<td>RCAR - Which group should address RCAR model issues?</td>
<td>ESWG Consideration</td>
</tr>
<tr>
<td>Cycle: 18-month cycle not long enough (Board wants shorter timeframe); find efficiencies in model build to enable shorter process</td>
<td>18-mth Planning Cycle/ Common Planning Model</td>
</tr>
<tr>
<td>Planning Horizon: ITP-NT only looks out 5 years, creating gap with ITP-10 for years 6-9</td>
<td>18-mth Planning Cycle/Holistic Planning Process/ Common Planning Model</td>
</tr>
<tr>
<td>Planning Horizon: Disconnect between ITP-NT and multi-year view of flowgates depending on viewpoint of the party looking at them</td>
<td>18-mth Planning Cycle/Holistic Planning Process</td>
</tr>
<tr>
<td>Planning Horizon: No long-term planning for real-time markets; may need policy change</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Quantity: Don’t do enough futures and the amount is limited by rate impact concerns</td>
<td>Standardized Scope</td>
</tr>
<tr>
<td>Type: No sensitivities around gas/wind prices (gen build); consider doing sensitivities when doing generation build</td>
<td>ESWG Consideration</td>
</tr>
<tr>
<td>Type: No economic assessment in the ITP-NT; add economics to ITP-NT</td>
<td>18-mth Planning Cycle/Holistic Planning Process</td>
</tr>
<tr>
<td>Type: Supply and demand build (beyond # of futures) not robust; not enough time evaluating gen and supply issues (gas prices, etc.)</td>
<td>18-mth Planning Cycle/Holistic Planning Process</td>
</tr>
<tr>
<td>Approach: SPP methodology is inconsistent in how futures are treated; impacts final design</td>
<td>Standardized Scope</td>
</tr>
<tr>
<td>Quality: Lack of planning beyond N-1 (less robust system); consider new TPL requirements and regional funding mechanism for compliance</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>TPITF Issue</td>
<td>Classification</td>
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<td>----------------------------------------------------------------------------</td>
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</tr>
<tr>
<td>Quality: Don't consider infrastructure age and condition in planning studies</td>
<td>Review Completed</td>
</tr>
<tr>
<td>Quality: Inconsistency on how non-transmission alternatives are handled can lead to sub-optimal outcomes; more options needed; policy consideration</td>
<td>Review Completed</td>
</tr>
<tr>
<td>Methodology: Unclear whether TCRs are accounted for in ITP process. Resource cost (no congestion) verses LMPs. Resource cost captures the TCR.</td>
<td>ESWG Consideration</td>
</tr>
<tr>
<td>Methodology: 1-year benefits-to-cost ratio may not be adequate; is 0.9 the right cutoff level?</td>
<td>ESWG Consideration</td>
</tr>
<tr>
<td>Methodology: Generation location modeling in ITP-10 is off-base; do we need to model generation where it's going in? Incorporate the GI queue.</td>
<td>Standardized Scope</td>
</tr>
<tr>
<td>Methodology: No transfer analysis for in-process construction, if not specifically called for in study scope (ties back to need for more information)</td>
<td>ESWG Consideration</td>
</tr>
<tr>
<td>Methodology Could a deliverability study count toward the 12% capacity margin requirement for CDR (capacity and demand reserve) purposes? CMTF looking into this.</td>
<td>CMTF Consideration</td>
</tr>
<tr>
<td>Methodology: More consistent use of benefit metrics through the process, both year-to-year and process to process</td>
<td>Standardized Scope</td>
</tr>
<tr>
<td>Equitability: Scenario 5 near-term models may not be sufficient to preserve rights of long-term firm transmission. Reflective of how the system is used to preserve the LT rights? Assumes wind at 100% on-peak (not accurate). Could cause over-build of the system due to unrealistic dispatch. High-wind better in a shoulder or off-peak case. Service: Financial vs physical firm. Developed pre-market.</td>
<td>Common Planning Model</td>
</tr>
<tr>
<td>Value Creation: May be missing opportunities to develop solutions that could be leveraged through off-takers outside the SPP footprint</td>
<td>Holistic Planning Process/18-month Planning Cycle</td>
</tr>
<tr>
<td>ITPNT and ITP10 built to address different needs.</td>
<td>18-mth Planning Cycle/Holistic Planning Process</td>
</tr>
<tr>
<td>ProMod: Tool uses generic data vs. replicating what's happening in the new market</td>
<td>ESWG Consideration</td>
</tr>
<tr>
<td>ProMod: Tool has memory limitations; need to explore better use of hardware and software supporting our planning processes</td>
<td>Staff/ESWG Consideration</td>
</tr>
<tr>
<td>Policy: Do we need ITP-20 given we already have option of special high-priority study if we end up needing that data set?</td>
<td>18-mth Planning Cycle</td>
</tr>
<tr>
<td>TPITF Issue</td>
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<td>---------------------------------------------------------------------------</td>
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<tr>
<td>Policy: No long-term planning for real-time markets; seeing flowgates that aren't getting fixed. Economic and Reliability screens. may need policy change</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Timelines: Timelines don't align across SPP ITP, MISO MTEP, and IPSAC processes</td>
<td>18-mth Planning Cycle</td>
</tr>
<tr>
<td>Timelines: Study duration timelines (predetermined) often do not reflect scope of work required</td>
<td>18-mth Planning Cycle/Standardized Scope</td>
</tr>
<tr>
<td>Timelines: Timing of ITP-10 minimizes any positive impact that may result (no flexibility)</td>
<td>18-mth Planning Cycle</td>
</tr>
<tr>
<td>FERC: Unclear whether NTC re-evaluation process is still appropriate given Order 1000</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>FERC: Order 1000 had a large impact on the amount and scope of work for the planning processes</td>
<td>CTPTF Consideration</td>
</tr>
<tr>
<td>Cycle Impact: High regulatory bar conflicts with desire to go faster</td>
<td>18-mth Planning Cycle</td>
</tr>
<tr>
<td>Market-to-market: Unclear how market-to-market impacts should be addressed in the planning process</td>
<td>Standardized Scope</td>
</tr>
<tr>
<td>Too much transmission service protection; duplication leads to overbuilding</td>
<td>Common Planning Model</td>
</tr>
<tr>
<td>NTCs: No mechanism to administer NTCs from TPL studies; should we fold into ITP-NT process or revise tariff to give TPL authority to administer NTCs?</td>
<td>18-mth Planning Cycle/Holistic Planning Process</td>
</tr>
<tr>
<td>Efficiency: Redundancy of model/contingency sets suggest need to combine all or parts of ITP-NT, TPL and/or ITP10</td>
<td>Common Planning Model/Holistic Planning Process</td>
</tr>
<tr>
<td>Efficiency: Having to run separate AQ process creates inefficiency vs. including in ITP-NT where possible or not having TOs perform the studies</td>
<td>AQITF will address</td>
</tr>
<tr>
<td>Bifurcation of planning process and NERC planning standards</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Accuracy: Difficult to accurately reflect external systems with each planning process (impacts accuracy of regional results)</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Completeness: No mechanism to capture/fix all seams needs to ensure comprehensive planning (East not getting appropriate benefits?)</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Timeliness: Interregional planning is a two-party process, which can cause timeline issues</td>
<td>18-mth Planning Cycle/Holistic Planning Process</td>
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<tr>
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<tr>
<td>Timeliness: Planning processes don't align with inter-regional processes</td>
<td>18-mth Planning Cycle/Holistic Planning Process</td>
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<tr>
<td>Resource: Not enough SPP resource to expand value of long-range planning; need honest cost assessment to align budget with study expectations</td>
<td>Staff/Stakeholder Accountability</td>
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<tr>
<td>Responsiveness: Projects showing up at the last minute due to a lack of foresight</td>
<td>Holistic Planning Process/TWG Consideration</td>
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<tr>
<td>Collaboration: Need fundamental principles balanced with back-end direction</td>
<td>Standardized Scope</td>
</tr>
<tr>
<td>Time spent on studies not used/leveraged in other processes. What's the value of the studies? Are we utilizing the results? - ERAG, EIPC, JOA, ITP20</td>
<td>Review Completed</td>
</tr>
<tr>
<td>Lack of Engineering Economic Analysis. Consider costs, etc. when evaluating and selecting a project(s) as a fix. Bridge to operational planning.</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Misalignment of stakeholder incentives; RCAR. Plan system regionally and look at cost allocation etc. via zone.</td>
<td>Review Completed</td>
</tr>
<tr>
<td>Inefficient staff resource usage. Time not spent on the development of regional plan due to work from WGs outside of planning studies scopes.</td>
<td>Standardized Scope/Staff/Stakeholder Accountability</td>
</tr>
<tr>
<td>Lack of higher-level vision for studies; reactive planning vs pro-active planning. Tactical and short-term vs long-term strategic plan.</td>
<td>18-mth Planning Cycle/Holistic Planning Process</td>
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<tr>
<td>Lack of detailed project analysis. Higher-level vs detailed project analysis. Issues: study scope, delays in the schedule (time crunch)</td>
<td>Standardized Scope/Staff/Stakeholder Accountability</td>
</tr>
<tr>
<td>Projects screened out or selected based on cost estimates that may not be accurate.</td>
<td>Staff Consideration</td>
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<tr>
<td>Too slow to accept new realities; CBA, TPL, CPP</td>
<td>Holistic Planning Process</td>
</tr>
<tr>
<td>Assignment of costs associated with siting generation due to the location of a flowgate (mkt). Have to work around the issue.</td>
<td>Staff Consideration</td>
</tr>
<tr>
<td>Direction: SPP staff feels we do not have enough guidance upfront; prefer fundamental principles with back-end discretion</td>
<td>Standardized Scope</td>
</tr>
<tr>
<td>Milestone Reviews: Requirement that working groups review each ITP-10 milestone creates elongated process; policy changes could speed updates</td>
<td>Standardized Scope</td>
</tr>
<tr>
<td>Consensus: Growing difficulty to build consensus toward approval of transmission plans</td>
<td>Standardized Scope</td>
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<tr>
<td>Changing of expectations; mid-process</td>
<td>Standardized Scope/Staff/Stakeholder Accountability</td>
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<tr>
<td>Conflicting member expectations</td>
<td>Standardized Scope/Staff/Stakeholder Accountability</td>
</tr>
<tr>
<td>Responsiveness: Too many planning processes at SPP - sheer number limits speed of member inputs</td>
<td>Common Planning Model/Standardized Scope</td>
</tr>
<tr>
<td>Organization: Planning processes at SPP too siloed (e.g., Aggregate Studies, Generator Interconnection) - should eliminate or consolidate</td>
<td>Common Planning Model/Holistic Planning Process</td>
</tr>
<tr>
<td>Resources: Limited member staff to participate in the process (results, models, etc.)</td>
<td>Staff/Stakeholder Accountability</td>
</tr>
<tr>
<td>Resources: SPP introducing software that entities don't have; as a result, they lose the ability to validate the data</td>
<td>Staff/Stakeholder Accountability</td>
</tr>
<tr>
<td>Lack of feedback loop due to Order 1000. All projects considered competitive until deemed otherwise. Limits discussion regarding the projects until they are determined to be non-competitive.</td>
<td>CTPTF Consideration</td>
</tr>
<tr>
<td>Incentive points awarded for DPP submission creates issues. DPPs submitted just to get bonus points. 1-step vs 2-step</td>
<td>CTPTF Consideration</td>
</tr>
<tr>
<td>Flowgates: Operations and Planning coordinate on annual flowgate assessment but don't create actual solutions; consider merging with ITP-NT process and adding solutions (at least enable quarterly removal of flowgates)</td>
<td>Standardized Scope/Holistic Planning Process</td>
</tr>
<tr>
<td>Generation: Expectations for generation at odds with reality, as evidenced in gaps between GI/Agg Studies and ITP (are assumptions on delivery different; should they be?)</td>
<td>Common Planning Model</td>
</tr>
<tr>
<td>Integration: Processes don’t tend to “talk” to each other – can GI and Aggregate study results be better integrated into other studies?</td>
<td>Common Planning Model/Holistic Planning Process</td>
</tr>
<tr>
<td>Process Clarity: No distinction on what you get between ERIS and NRIS</td>
<td>Staff Consideration</td>
</tr>
<tr>
<td>Regulatory: Unclear of impact to LTCR outcomes based on upcoming Boston Energy FERC compliance ruling (is it an issue?)</td>
<td>MWG/CAWG Consideration</td>
</tr>
<tr>
<td>Methodology: TSS assumes all firm service is rolled over; no mechanism to verify roll-over of service in planning processes. How addressed since all service is modeled in perpetuity. How to consider service in the out-years. No transactions in the ITP10 but captured in the ITPNT.</td>
<td>Common Planning Model/Holistic Planning Process</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
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<tr>
<td>ARR</td>
<td>Auction Revenue Rights</td>
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<tr>
<td>BPWG</td>
<td>Business Practice Working Group</td>
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<tr>
<td>CAWG</td>
<td>Cost Allocation Working Group</td>
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<tr>
<td>CBA</td>
<td>Consolidated Balancing Authority</td>
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<tr>
<td>DPP</td>
<td>Detailed Project Proposal</td>
</tr>
<tr>
<td>ESWG</td>
<td>Economic Studies Working Group</td>
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<tr>
<td>IROL</td>
<td>Interconnection Reliability Operating Limits</td>
</tr>
<tr>
<td>ITP</td>
<td>Integrated Transmission Planning</td>
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<tr>
<td>ITP10</td>
<td>ITP 10-Year Assessment</td>
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<tr>
<td>ITP20</td>
<td>ITP 20-Year Assessment</td>
</tr>
<tr>
<td>ITPNT</td>
<td>ITP Near-term Assessment</td>
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<tr>
<td>MDWG</td>
<td>Model Development Working Group</td>
</tr>
<tr>
<td>MOPC</td>
<td>SPP Market and Operations Policy Committee</td>
</tr>
<tr>
<td>NERC</td>
<td>North American Electric Reliability Corporation</td>
</tr>
<tr>
<td>NITS</td>
<td>Network Integration Transmission Service</td>
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<tr>
<td>NTC</td>
<td>Notifications to Construct</td>
</tr>
<tr>
<td>OATT</td>
<td>Open Access Transmission Tariff</td>
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<tr>
<td>RCWG</td>
<td>Regional Compliance Working Group</td>
</tr>
<tr>
<td>RMS</td>
<td>SPP Request Management System</td>
</tr>
<tr>
<td>RR</td>
<td>Request Revision process</td>
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<tr>
<td>RSC</td>
<td>Regional State Committee</td>
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<tr>
<td>RTWG</td>
<td>Regional Tariff Working Group</td>
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<tr>
<td>SPC</td>
<td>SPP Strategic Planning Committee</td>
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<tr>
<td>SSC</td>
<td>Seams Steering Committee</td>
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<tr>
<td>TCR</td>
<td>Transmission Congestion Rights</td>
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<tr>
<td>TWG</td>
<td>Transmission Working Group</td>
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</tbody>
</table>
Southwest Power Pool, Inc.
REGIONAL STATE COMMITTEE
Pending Action Items Status Report

<table>
<thead>
<tr>
<th>No.</th>
<th>Action Item</th>
<th>Date Originated</th>
<th>Status</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>Consideration of RSC Bylaws changes related to membership eligibility</td>
<td>Ongoing</td>
<td>Ongoing</td>
<td>Discussed at December 1, 2014 meeting, January 2015 Educational Session and March 9, 2015 Meeting. Action is needed by July 2015 meeting. A small group of RSC Commissioners (Albrecht, Davis and Nelson, along with Commissioner Kalk from North Dakota) will review the bylaws and report back to the RSC for further consideration. This was discussed at the RSC retreat and meeting on July 27, 2015. Bylaws changes were considered at the September 21, 2015 meetings but were not approved. Changes to the Bylaws may be considered again at a later time. January 25, 2016 – RSC Goal for 2016 to consider adopting the clean-up of the Bylaws discussed in 2015.</td>
</tr>
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<tr>
<td>12</td>
<td>RSC Role in Cost Allocation for New Member Integrations</td>
<td>4/27/2015</td>
<td>In Process.</td>
<td>In January 2015, the RSC tasked the CAWG with looking at what role the RSC should have in regards to Cost Allocation methodology for new members joining SPP. At the April RSC educational session the RSC heard a presentation from Carl Monroe on the history of integrating new members in SPP and had a discussion with CAWG members regarding the Nebraska integration, IS integration, and areas of interest from RSC &amp; CAWG members. After discussion on the topic, the RSC tasked the CAWG to develop a scoping document on how to apply cost allocation for new members joining SPP. The Scope Document developed by CAWG was approved by the RSC on July 27, 2015 and CAWG is moving forward with its analysis of this issue. CAWG continues to work on this item.</td>
</tr>
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<tr>
<td>13</td>
<td>Aggregate Study Waiver Criteria</td>
<td>4/27/2015</td>
<td>In Process</td>
<td>While discussing a request for waiver of the eligibility requirements of Section III.B.1 of Attachment J for a request for a new Designated Wind Resource, the RSC determined it should review the eligibility requirements set out in Section III.B.1 (specifically the 20% threshold), and whether the requirements are applicable today in light of the changes to the transmission system since the requirements were approved. The RSC tasked the CAWG to evaluate the eligibility requirements for a waiver request to see if the requirements are still applicable to the transmission system as it operates now. CAWG presented a draft scoping document to the RSC on July 27, 2015. The RSC asked CAWG to evaluate whether the RSC consultant was needed, and if so to develop a scope of work, or whether SPP staff could provide the necessary background and analysis. The draft scope document was approved by CAWG on October 6, 2015 and by the RSC on October 26, 2015. <strong>CAWG continues to work on this item.</strong></td>
</tr>
<tr>
<td>14</td>
<td>Capacity Margin Task Force Update</td>
<td>4/27/2015</td>
<td>In Process</td>
<td>After a presentation at the April 2015 RSC meeting, and discussion on the Capacity Margin Task Force, the RSC tasked the CAWG to evaluate how load is forecasted for the purpose of determining the reserve margin. CAWG reported back to the RSC on load forecasting at their July meeting and the RSC provided no further action to the CAWG on this item. Updates on the CMTF activities were provided to the MOPC, RSC and BOD at the July 2015 and October 2015 meetings. This item remains ongoing and an update was provided at the January 2016 RSC meeting. <strong>This is anticipated to be a voting item at the April 2016 meeting.</strong></td>
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<tr>
<td>15</td>
<td>RSC Goals for 2016</td>
<td>1/25/2016</td>
<td>Ongoing</td>
<td>RSC discussed goals for 2016 at the January 2016 Educational Session. Any additional goals should be submitted to Erin Cullum for distribution in advance of the April 2016 RSC meeting.</td>
</tr>
<tr>
<td>16</td>
<td>Engagement Term of RSC Auditor</td>
<td>1/25/2016</td>
<td>In Process</td>
<td>Determine the initial arrangement with the RSC auditor and the number of years for reengagement. Erin Cullum will review the agreement and inform the RSC.</td>
</tr>
<tr>
<td>17</td>
<td>Educational Session Topic Request – Role of RSC in SPP FERC Filings</td>
<td>1/25/2016</td>
<td>In Process</td>
<td>Request for SPP Staff to provide educational update on the FERC filings process and the role of the RSC.</td>
</tr>
<tr>
<td>18</td>
<td>Talking Points on CPP</td>
<td>1/25/2016</td>
<td>In Process</td>
<td>Request for SPP’s talking points on the CPP. Erin Cullum will distribute the link to posted comments.</td>
</tr>
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| 1   | EPA 111(d) : (1) Lanny Nickell to provide scope document on compliance analysis and an update on when SPP reliability analysis will be completed  
(2) Commissioner Reeves to provide update on possibility of studies to be performed by BPC and GPI, what services those entities are providing | 8/25/2014       | Completed | Addressed at 9/29/14 Meeting                                              |
<p>| 2   | RARTF: Update on RARTF and New Metrics                                      | 8/25/2014       | Completed | Addressed at 9/29/14 Meeting                                              |
| 3   | Seams Project Task Force: CAWG will consider the issue at next meeting and bring back to RSC for discussion | 8/25/2014       | Completed | Addressed at 9/29/14 Meeting; On 10/27/14 Meeting as a voting item       |
| 4   | SPC Task Force on New Members: RSC should email Commissioner Murphy with any concerns or topics. Update to be provided at next RSC meeting | 8/25/14         | Completed | Addressed at 9/29/14 Meeting                                              |</p>
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<tr>
<td>7</td>
<td>SPC Task Force on New Members – Discuss 3 RSC Action Items</td>
<td>9/29/2014</td>
<td>Complete</td>
<td>Discussed at October 27, 2014 Meeting and December 1, 2014 Meeting. On January 2015 Educational Session for discussion and January 2015 Meeting Agenda as a voting item. Feedback was provided to SPC TF on NM on items 1 and 2 on January 26, 2015 and subsequent to the March 9, 2015 RSC teleconference. The RSC will continue to discuss item 3 on cost allocation and has delegated this item to the CAWG (Action Item 12). On July 27, 2015, the RSC approved a scoping document developed by CAWG. The SPC TF on New Members finalized its report, which was approved by the SPC in July 2015. The RSC approved the New Member Process document with the addition of catch-al language permitting the RSC to invoke the new member process for matters within the RSC’s responsibility.</td>
</tr>
<tr>
<td>9</td>
<td>Goals and Objectives for 2015 RSC Year</td>
<td>12/1/2014</td>
<td>Complete</td>
<td>Discussed at December 1, 2014 meeting and draft goals were reviewed on January 26, 2015, March 9, 2015, April 27, 2015 and September 21, 2015.</td>
</tr>
<tr>
<td>11</td>
<td>Educational Session on SPP “Building Blocks”</td>
<td>1/25/2015</td>
<td>Removed</td>
<td>Educational Session on the SPP “Building Blocks” – possible topic for July retreat. Unclear what this was intended to cover. Removed when list of retreat topics was updated.</td>
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<tr>
<td>Balanced Portfolio</td>
<td>13</td>
</tr>
<tr>
<td>Priority Projects</td>
<td>15</td>
</tr>
<tr>
<td>2012 ITP10</td>
<td>17</td>
</tr>
<tr>
<td>Out-of-Bandwidth Projects</td>
<td>19</td>
</tr>
<tr>
<td>Responsiveness Report</td>
<td>20</td>
</tr>
<tr>
<td>Appendix 1</td>
<td>22</td>
</tr>
</tbody>
</table>
EXECUTIVE SUMMARY

SPP actively monitors and supports the progress of transmission expansion projects, emphasizing the importance of maintaining accountability for areas such as grid regional reliability standards, firm transmission commitments and Tariff cost recovery.

Each quarter SPP staff solicits feedback from the project owners to determine the progress of each approved transmission project. This quarterly report charts the progress of all SPP Transmission Expansion Plan (STEP) projects approved either directly by the SPP Board of Directors (Board) or through a FERC filed service agreement under the SPP Open Access Transmission Tariff (OATT).

The reporting period for this report is November 1, 2015 through January 31, 2016. Table 1 provides a summary of all projects in the current Project Tracking Portfolio (PTP), which includes all Network Upgrades in which construction activities are ongoing, or construction has completed but not all the close-out requirements have been fulfilled in accordance to Section 13 of Business Practice 7060. The PTP includes all active Network Upgrades including transmission lines, transformers, substations, and devices.

Table 1 below summarizes the PTP for this quarter. Figures 1 reflects the percentage cost of each upgrade type in the PTP. Figure 2 shows the percentage cost of each project status in the PTP.

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>No. of Upgrades</th>
<th>Estimated Cost</th>
<th>Miles of New</th>
<th>Miles of Rebuild</th>
<th>Miles of Voltage Conversion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Economic</td>
<td>4</td>
<td>$39,710,956</td>
<td>0.0</td>
<td>0.0</td>
<td>28.8</td>
</tr>
<tr>
<td>High Priority</td>
<td>83</td>
<td>$1,335,949,052</td>
<td>947.1</td>
<td>16.6</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability</td>
<td>296</td>
<td>$2,874,834,527</td>
<td>1592.0</td>
<td>463.2</td>
<td>386.4</td>
</tr>
<tr>
<td>Transmission Service</td>
<td>21</td>
<td>$88,701,139</td>
<td>12.7</td>
<td>15.3</td>
<td>0.0</td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>9</td>
<td>$108,886,545</td>
<td>34.7</td>
<td>28.5</td>
<td>0.0</td>
</tr>
<tr>
<td>NTC Projects Subtotal</td>
<td>413</td>
<td>$4,448,082,219</td>
<td>2586.5</td>
<td>523.6</td>
<td>415.2</td>
</tr>
<tr>
<td>Generation Interconnection</td>
<td>71</td>
<td>$277,319,428</td>
<td>20.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Regional Reliability - Non OATT</td>
<td>1</td>
<td>$7,107,090</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>TO - Sponsored</td>
<td>6</td>
<td>$38,738,536</td>
<td>10.7</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Non-NTC Projects Subtotal</td>
<td>78</td>
<td>$323,165,054</td>
<td>30.7</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>491</strong></td>
<td><strong>$4,771,247,273</strong></td>
<td><strong>2617.2</strong></td>
<td><strong>523.6</strong></td>
<td><strong>415.2</strong></td>
</tr>
</tbody>
</table>

Table 1: Q2 2016 Portfolio Summary
Figure 1: Percentage of Project Type on Cost Basis

- Economic: 0.8%
- Generation Interconnection: 2%
- High Priority: 6%
- Regional Reliability: 28%
- Transmission Service: 61%
- Zonal Reliability: 2%

Figure 2: Percentage of Project Status on Cost Basis

- Closed Out: 1%
- Complete: 32%
- On Schedule < 4: 3%
- On Schedule > 4: 2%
- Delay - Mitigation: 0.4%
- Suspended: 3%
- NTC - Commitment Window: 17%
- RFP Response Window: 5%
- Re-evaluation: 38%
In adherence to the OATT and Business Practice 7060, SPP issues Notifications to Construct (NTCs) to Designated Transmission Owners (DTOs) to commence the construction of Network Upgrades that have been approved or endorsed by the Board intended to meet the construction needs of the STEP, OATT, or Regional Transmission Organization (RTO).

Figure 3 reflects project status within each source study, and Table 2 provides the supporting data. Figure 4 shows the amount of estimated cost by in-service year for all Network Upgrades that have been issued an NTC or NTC-C. **Note: Figures 3 and 4, and Table 2 provide data for all projects for which SPP has issued an NTC or NTC-C, regardless of completion date, and therefore include data from Network Upgrades no longer included in PTP.**

![Figure 3: Project Status by NTC Source Study](image-url)
<table>
<thead>
<tr>
<th>Source Study</th>
<th>Complete</th>
<th>Delayed</th>
<th>Suspended</th>
<th>On Schedule</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006 STEP</td>
<td>$187,367,084</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$187,367,084</td>
</tr>
<tr>
<td>2007 STEP</td>
<td>$504,976,613</td>
<td>$17,964,000</td>
<td>$0</td>
<td>$0</td>
<td>$522,940,613</td>
</tr>
<tr>
<td>2008 STEP</td>
<td>$416,670,179</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$416,670,179</td>
</tr>
<tr>
<td>Balanced Portfolio</td>
<td>$831,489,690</td>
<td>$1,400,000</td>
<td>$0</td>
<td>$0</td>
<td>$832,889,690</td>
</tr>
<tr>
<td>Priority Projects</td>
<td>$854,531,082</td>
<td>$127,995,000</td>
<td>$0</td>
<td>$336,433,874</td>
<td>$1,318,959,956</td>
</tr>
<tr>
<td>2010 STEP</td>
<td>$104,984,018</td>
<td>$31,785,046</td>
<td>$0</td>
<td>$2,332,800</td>
<td>$139,101,864</td>
</tr>
<tr>
<td>2012 ITPNT</td>
<td>$146,150,500</td>
<td>$42,412,744</td>
<td>$0</td>
<td>$456,837,706</td>
<td>$770,312,946</td>
</tr>
<tr>
<td>2013 ITPNT</td>
<td>$207,206,950</td>
<td>$260,103,615</td>
<td>$0</td>
<td>$41,462,612</td>
<td>$508,773,177</td>
</tr>
<tr>
<td>2014 ITPNT</td>
<td>$33,296,785</td>
<td>$365,140,517</td>
<td>$0</td>
<td>$226,631,488</td>
<td>$625,068,790</td>
</tr>
<tr>
<td>HPILS</td>
<td>$155,106,457</td>
<td>$140,013,324</td>
<td>$0</td>
<td>$535,440,754</td>
<td>$830,560,535</td>
</tr>
<tr>
<td>2015 ITPNT</td>
<td>$0</td>
<td>$232,387,459</td>
<td>$36,731,836</td>
<td>$2,473,636</td>
<td>$293,592,930</td>
</tr>
<tr>
<td>2015 ITP10</td>
<td>$0</td>
<td>$2,200,956</td>
<td>$0</td>
<td>$76,052,596</td>
<td>$78,253,551</td>
</tr>
<tr>
<td>IS Integration Study</td>
<td>$205,500,000</td>
<td>$38,000,000</td>
<td>$0</td>
<td>$116,800,000</td>
<td>$360,300,000</td>
</tr>
<tr>
<td>Ag Studies</td>
<td>$693,910,706</td>
<td>$67,906,168</td>
<td>$0</td>
<td>$91,629,214</td>
<td>$854,446,088</td>
</tr>
<tr>
<td>DPA Studies</td>
<td>$158,054,495</td>
<td>$25,683,370</td>
<td>$0</td>
<td>$7,652,131</td>
<td>$191,389,996</td>
</tr>
<tr>
<td>GI Studies</td>
<td>$460,359,584</td>
<td>$319,566</td>
<td>$0</td>
<td>$213,035,984</td>
<td>$673,715,133</td>
</tr>
<tr>
<td>Total</td>
<td>$5,489,147,229</td>
<td>$1,666,688,388</td>
<td>$36,731,836</td>
<td>$2,128,782,794</td>
<td>$9,321,350,247</td>
</tr>
</tbody>
</table>

Table 2: Project Status by NTC Source Study

Figure 4: Estimated Cost for NTC Project per In-Service Year
**NTC ISSUANCE**

Five new NTCs were issued since the last quarterly report totaling an estimated $46.9 million.

NTCs were issued for 10 new upgrades as a result of the completion of Aggregate Studies SPP-2013-AG3-AFS-6, SPP-2014-AG1-AFS-6, and SPP-2015-AG1-AFS-6. The total estimated cost of the new Aggregate Study upgrades is $39.7 million.

Two NTCs were issued as a result of completed Generation Interconnection studies GEN-2011-019 and GEN-2014-021, with a combined estimated cost of $7.2 million.

Three NTC modifications were issued to Southwestern Public Service Company (SPS) to detail project scope changes approved by the Board at its January 2016 meeting.

NTC No. 200371 was issued to SPS after the Board approved Staff’s recommendation to remove the conditions of a previously issued Notification to Construct with Conditions (NTC-C). The NTC-C was issued as a result of the 2015 ITP Near-Term Assessment approved by the Board in January 2015. The total estimated cost of the Network Upgrades described in this NTC is $54.8 million.

Table 3 summarizes the NTC activity from January 1, 2016 through March 31, 2016. NTC ID values in bold font indicate NTC-Cs.

<table>
<thead>
<tr>
<th>NTC ID</th>
<th>DTO</th>
<th>NTC Issue Date</th>
<th>Upgrade Type</th>
<th>Source Study</th>
<th>No. of Upgrades</th>
<th>Estimated Cost of New Upgrades</th>
<th>Estimated Cost of Previously Approved Upgrades</th>
</tr>
</thead>
<tbody>
<tr>
<td>200365</td>
<td>SPS</td>
<td>1/12/2016</td>
<td>Regional Reliability</td>
<td>SPP-2014-AG1-AFS-6</td>
<td>8</td>
<td>$29,976,259</td>
<td></td>
</tr>
<tr>
<td>200366</td>
<td>SPS</td>
<td>1/12/2016</td>
<td>Transmission Service</td>
<td>SPP-2013-AG3-AFS-6</td>
<td>1</td>
<td>$9,485,379</td>
<td></td>
</tr>
<tr>
<td>200367</td>
<td>OPPD</td>
<td>1/12/2016</td>
<td>Generation Interconnection</td>
<td>GEN-2014-021</td>
<td>1</td>
<td>$122,455</td>
<td></td>
</tr>
<tr>
<td>200368</td>
<td>SPS</td>
<td>2/12/2016</td>
<td>Regional Reliability</td>
<td>2010 STEP</td>
<td>1</td>
<td>$10,316,217</td>
<td></td>
</tr>
<tr>
<td>200369</td>
<td>SPS</td>
<td>2/12/2016</td>
<td>Regional Reliability</td>
<td>SPP-2011-AG3-AFS-11</td>
<td>2</td>
<td>$15,500,876</td>
<td></td>
</tr>
<tr>
<td>200370</td>
<td>SPS</td>
<td>2/12/2016</td>
<td>High Priority</td>
<td>HPILS</td>
<td>1</td>
<td>$10,671,660</td>
<td></td>
</tr>
<tr>
<td>200371</td>
<td>SPS</td>
<td>2/12/2016</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>2</td>
<td>$54,843,257</td>
<td></td>
</tr>
<tr>
<td>200375</td>
<td>OGE</td>
<td>3/11/2016</td>
<td>Generation Interconnection</td>
<td>GEN-2011-019</td>
<td>1</td>
<td>$7,099,999</td>
<td></td>
</tr>
<tr>
<td>200377</td>
<td>WR</td>
<td>3/17/2016</td>
<td>Transmission Service</td>
<td>SPP-2015-AG1-AFS-6</td>
<td>1</td>
<td>$200,000</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>18</td>
<td>$46,884,092</td>
<td>$91,332,010</td>
</tr>
</tbody>
</table>
**NTC WITHDRAW**

One NTC was withdrawn for two Network Upgrades since the last quarterly report, totaling an estimated $41.5 million.

Both of the withdrawn Network Upgrades were determined to no longer be needed as a part of the ongoing 2016 ITP Near-Term Assessment. The Board approved the withdrawals at its meeting in January 2016.

Table 4 lists the NTC Withdraw activity from January 1, 2016 through March 31, 2016. NTC ID values in **bold** font indicate NTC-Cs.

<table>
<thead>
<tr>
<th>NTC ID</th>
<th>DTO</th>
<th>NTC Withdraw Date</th>
<th>Upgrade Type</th>
<th>Original Source Study</th>
<th>No. of Upgrades</th>
<th>Estimated Cost of Withdrawn Upgrades</th>
</tr>
</thead>
<tbody>
<tr>
<td>200372</td>
<td>AEP</td>
<td>2/12/2016</td>
<td>Regional Reliability</td>
<td>2015 ITPNT</td>
<td>2</td>
<td>$41,520,892</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>Total</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2</td>
<td><strong>$41,520,892</strong></td>
</tr>
</tbody>
</table>

_Table 4: Q1 2016 NTC Withdraw Summary_
**COMPLETED PROJECTS**

Twenty-three (23) Network Upgrades with NTCs, six Base Plan Funded Network Upgrades via the Integrated System Integration, and one Generation Interconnection Network Upgrade were verified as completed during the reporting period, totaling an estimated $309.3 million.

Table 5 lists the Network Upgrades reported and confirmed as completed during the reporting period. Table 6 summarizes the completed projects over the previous year, including Network Upgrades not yet confirmed as completed. Figure 5 reflects the completed projects by upgrade type on a cost basis for the current year and the following year based on current projected in-service dates. Tables 7 and 8 summarize all Network Upgrades that include construction of transmission lines, both for the current year and the following year. **Note: Previous quarter’s updated results are listed as the Transmission Owners may make adjustments to final costs and status of projects completed during the year.**

<table>
<thead>
<tr>
<th>UID</th>
<th>Network Upgrade Name</th>
<th>Owner</th>
<th>NTC Source Study</th>
<th>Cost Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>10414</td>
<td>Tyler - Westlink 69 kV Ckt 1 Rebuild</td>
<td>WR</td>
<td>Ag Studies</td>
<td>$6,278,731</td>
</tr>
<tr>
<td>10828</td>
<td>ARTESIA SOUTH RURAL SUB - ARTESIA TOWN SUB 69KV Ckt 1</td>
<td>SPS</td>
<td>2008 STEP</td>
<td>$4,385,939</td>
</tr>
<tr>
<td>11007</td>
<td>HAPPY INTERCHANGE 115/69KV TRANSFORMER Ckt 1</td>
<td>SPS</td>
<td>2010 STEP</td>
<td>$1,518,414</td>
</tr>
<tr>
<td>11101</td>
<td>PORTALES INTERCHANGE - ZODIAC 115KV Ckt 1</td>
<td>SPS</td>
<td>2009 STEP</td>
<td>$6,500,000</td>
</tr>
<tr>
<td>11104</td>
<td>Convert Muleshoe 69 kV to 115 kV</td>
<td>SPS</td>
<td>2012 ITPNT</td>
<td>$3,000,000</td>
</tr>
<tr>
<td>11110</td>
<td>Graham Interchange 115/69 kV Transformer Ckt 1</td>
<td>SPS</td>
<td>2013 ITPNT</td>
<td>$2,035,000</td>
</tr>
<tr>
<td>11318</td>
<td>Swisher County Interchange 230/115 kV Ckt 1</td>
<td>SPS</td>
<td>2014 ITPNT</td>
<td>$2,850,475</td>
</tr>
<tr>
<td>11512</td>
<td>Channing - Potter County 230 kV Ckt 1</td>
<td>SPS</td>
<td>2013 ITPNT</td>
<td>$1,775,315</td>
</tr>
<tr>
<td>11514</td>
<td>Channing - XIT 230 kV Ckt 1</td>
<td>SPS</td>
<td>2013 ITPNT</td>
<td>$9,171,505</td>
</tr>
<tr>
<td>11515</td>
<td>XIT 230/15/13.2 kV Transformer Ckt 1</td>
<td>SPS</td>
<td>2013 ITPNT</td>
<td>$1,954,807</td>
</tr>
<tr>
<td>50103</td>
<td>Vaughn 115 kV Cap Bank</td>
<td>WR</td>
<td>2014 ITPNT</td>
<td>$825,428</td>
</tr>
<tr>
<td>50230</td>
<td>ALTOONA EAST 69KV</td>
<td>WR</td>
<td>Ag Studies</td>
<td>$1,528,201</td>
</tr>
<tr>
<td>50401</td>
<td>Crosby 115 kV #2</td>
<td>SPS</td>
<td>2012 ITPNT</td>
<td>$1,265,432</td>
</tr>
<tr>
<td>50515</td>
<td>Deaf Smith County Interchange 230/115 kV Transformer Ckt 1 #2</td>
<td>SPS</td>
<td>Ag Studies</td>
<td>$4,236,816</td>
</tr>
<tr>
<td>50517</td>
<td>Ochiltree - Tri-County REC Cole 115 kV Ckt 1</td>
<td>SPS</td>
<td>2013 ITPNT</td>
<td>$12,470,000</td>
</tr>
<tr>
<td>50691</td>
<td>Butler - Weaver 138 kV Terminal Upgrades Ckt 1</td>
<td>WR</td>
<td>2014 ITPNT</td>
<td>$0</td>
</tr>
<tr>
<td>50727</td>
<td>Creswell - Sumner County No 4 Rome 69 kV Ckt 1</td>
<td>WR</td>
<td>2014 ITPNT</td>
<td>$4,259,395</td>
</tr>
<tr>
<td>50730</td>
<td>Crestview - Northeast 69 kV Ckt 1 Rebuild</td>
<td>WR</td>
<td>2014 ITPNT</td>
<td>$8,968,153</td>
</tr>
<tr>
<td>50763</td>
<td>Ahlosco - Park Lane 138 kV Ckt 1 Voltage Conversion</td>
<td>OGE</td>
<td>2014 ITPNT</td>
<td>$5,693,264</td>
</tr>
<tr>
<td>50873</td>
<td>Battle Axe - Road Runner 115 kV Ckt 1</td>
<td>SPS</td>
<td>HPILS</td>
<td>$7,785,501</td>
</tr>
<tr>
<td>50915</td>
<td>Park Lane 138 kV Terminal Upgrades</td>
<td>OGE</td>
<td>Ag Studies</td>
<td>$89,100</td>
</tr>
<tr>
<td>50968</td>
<td>Battle Axe 115 kV Substation</td>
<td>SPS</td>
<td>HPILS</td>
<td>$3,464,499</td>
</tr>
<tr>
<td>51014</td>
<td>Grady - Round Creek 138 kV Ckt 1</td>
<td>AEP</td>
<td>HPILS</td>
<td>$12,132,497</td>
</tr>
<tr>
<td>51306</td>
<td>AVS - Charlie Creek 345 kV Ckt 2</td>
<td>BEPC</td>
<td>IS Integration Study</td>
<td>$82,000,000</td>
</tr>
<tr>
<td>51308</td>
<td>Charlie Creek 345 kV Substation</td>
<td>BEPC</td>
<td>IS Integration Study</td>
<td>$9,000,000</td>
</tr>
<tr>
<td>51310</td>
<td>Charlie Creek - Judson 345 kV Ckt 1</td>
<td>BEPC</td>
<td>IS Integration Study</td>
<td>$82,000,000</td>
</tr>
<tr>
<td>51311</td>
<td>Judson 345/230 kV Substation</td>
<td>BEPC</td>
<td>IS Integration Study</td>
<td>$27,000,000</td>
</tr>
<tr>
<td>51312</td>
<td>Judson - Williston 230 kV Ckt 1</td>
<td>BEPC</td>
<td>IS Integration Study</td>
<td>$3,500,000</td>
</tr>
<tr>
<td>51313</td>
<td>Williston 230 kV Terminal Upgrades</td>
<td>BEPC</td>
<td>IS Integration Study</td>
<td>$2,000,000</td>
</tr>
<tr>
<td>51342</td>
<td>Renfrow 345 kV - add terminal for GEN-2013-029</td>
<td>OGE</td>
<td>GI Studies</td>
<td>$1,586,977</td>
</tr>
</tbody>
</table>

Total $309,277,448

Table 5: Q1 2016 Completed Network Upgrades
<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>Q2 2015</th>
<th>Q3 2015</th>
<th>Q4 2015</th>
<th>Q1 2016</th>
<th>Total</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Reliability</td>
<td>15</td>
<td>18</td>
<td>11</td>
<td>23</td>
<td>67</td>
<td>$527,288,375</td>
</tr>
<tr>
<td></td>
<td>$54,310,601</td>
<td>$149,275,236</td>
<td>$46,225,232</td>
<td>$277,477,306</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission Service</td>
<td>0</td>
<td>4</td>
<td>1</td>
<td>2</td>
<td>7</td>
<td>$22,170,852</td>
</tr>
<tr>
<td></td>
<td>$0</td>
<td>$15,753,551</td>
<td>$4,800,000</td>
<td>$1,617,301</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Balanced Portfolio</td>
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<td>0</td>
<td>0</td>
<td>3</td>
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<td></td>
<td>$62,949,252</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>High Priority</td>
<td>1</td>
<td>5</td>
<td>2</td>
<td>3</td>
<td>11</td>
<td>$105,794,841</td>
</tr>
<tr>
<td></td>
<td>$327,861</td>
<td>$22,184,483</td>
<td>$59,900,000</td>
<td>$23,382,497</td>
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</tr>
<tr>
<td>Economic</td>
<td>0</td>
<td>0</td>
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<td>0</td>
<td>0</td>
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<tr>
<td></td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Zonal Reliability</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>2</td>
<td>$1,180,428</td>
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<td></td>
<td>$0</td>
<td>$355,000</td>
<td>$0</td>
<td>$825,428</td>
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<td></td>
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<tr>
<td>Generation Interconnection</td>
<td>2</td>
<td>9</td>
<td>11</td>
<td>1</td>
<td>23</td>
<td>$116,195,927</td>
</tr>
<tr>
<td></td>
<td>$13,322,627</td>
<td>$56,639,246</td>
<td>$44,645,077</td>
<td>$1,588,977</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 6: Completed Project Summary through 1st Quarter 2016

![Figure 5: Completed Upgrades by Type per Quarter](image-url)
### Table 7: Line Upgrade Summary for Previous 12 Months

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>New</th>
<th>Rebuild/Reconductor</th>
<th>Voltage Conversion</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>18</td>
<td>71.6</td>
<td>60.3</td>
<td>0.0</td>
<td>$128,094,586</td>
</tr>
<tr>
<td>115</td>
<td>12</td>
<td>120.8</td>
<td>0.0</td>
<td>4.5</td>
<td>$90,529,129</td>
</tr>
<tr>
<td>138</td>
<td>7</td>
<td>13.7</td>
<td>9.0</td>
<td>24.4</td>
<td>$29,608,578</td>
</tr>
<tr>
<td>161</td>
<td>0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$0</td>
</tr>
<tr>
<td>230</td>
<td>5</td>
<td>87.9</td>
<td>0.0</td>
<td>122.0</td>
<td>$88,372,561</td>
</tr>
<tr>
<td>345</td>
<td>3</td>
<td>175.9</td>
<td>0.0</td>
<td>0.0</td>
<td>$226,949,252</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>45</strong></td>
<td><strong>469.8</strong></td>
<td><strong>69.3</strong></td>
<td><strong>150.9</strong></td>
<td><strong>$563,554,106</strong></td>
</tr>
</tbody>
</table>

### Table 8: Line Upgrade Projections for Next 12 Months

<table>
<thead>
<tr>
<th>Voltage Class</th>
<th>Number of Upgrades</th>
<th>New</th>
<th>Rebuild/Reconductor</th>
<th>Voltage Conversion</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>8</td>
<td>4.0</td>
<td>41.0</td>
<td>0.0</td>
<td>$31,860,222</td>
</tr>
<tr>
<td>115</td>
<td>7</td>
<td>116.1</td>
<td>10.3</td>
<td>0.0</td>
<td>$114,570,139</td>
</tr>
<tr>
<td>138</td>
<td>10</td>
<td>39.3</td>
<td>53.8</td>
<td>23.8</td>
<td>$81,074,567</td>
</tr>
<tr>
<td>161</td>
<td>0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$0</td>
</tr>
<tr>
<td>230</td>
<td>0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$0</td>
</tr>
<tr>
<td>345</td>
<td>7</td>
<td>376.7</td>
<td>0.0</td>
<td>0.0</td>
<td>$622,755,400</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>32</strong></td>
<td><strong>536.1</strong></td>
<td><strong>105.02</strong></td>
<td><strong>23.84</strong></td>
<td><strong>$850,260,328</strong></td>
</tr>
</tbody>
</table>
**PROJECT STATUS SUMMARY**

SPP assigns a project status to all Network Upgrades based on the projected in-service dates provided by the DTOs relative to the Need Date determined for the project. Project status definitions are provided below:

- **Complete**: Construction complete and in-service
- **Closed Out**: Construction complete and in-service; all close-out requirements fulfilled
- **On Schedule < 4**: On Schedule within 4-year horizon
- **On Schedule > 4**: On Schedule beyond 4-year horizon
- **Delayed**: Projected In-Service Date beyond Need Date; interim mitigation provided or project may change but time permits the implementation of project
- **Within NTC Commitment Window**: NTC/NTC-C issued, still within the 90-day written commitment to construct window and no commitment received
- **Within NTC-C Project Estimate Window**: Within the NTC-C Project Estimate (CPE) window
- **Within RFP Response Window**: RFP issued for the project
- **Re-evaluation**: Project active; pending re-evaluation
- **Suspended**: Project suspended; pending re-evaluation

Figure 6 reflects a summary of project status by upgrade type on a cost basis.
Approved in April 2009, the Balanced Portfolio was an initiative to develop a group of economic transmission upgrades that benefit the entire SPP region, and to allocate those project costs regionally. The projects that were issued NTCs as a result of the study include a diverse group of projects, estimated to add approximately 702 miles of new 345 kV transmission line to the SPP system.

The total cost estimate for the projects making up the Balanced Portfolio did not change from the previous quarter’s total of $831.5 million.

All the projects making up the Balanced Portfolio have been completed and placed into service. A final reallocation of Revenue Requirements for deficient Zone(s) will be performed once all actual costs have been reported.

Figure 7 below depicts a historical view of the total estimated cost of the Balanced Portfolio. Table 9 provides a project summary of the projects making up the Balanced Portfolio.

Figure 7: Balanced Portfolio Cost Estimate Trend
<table>
<thead>
<tr>
<th>Project ID(s)</th>
<th>Project Owner(s)</th>
<th>Project Name</th>
<th>Estimated Line Length</th>
<th>Study Estimates</th>
<th>Q3 2015 Cost Estimates</th>
<th>Q4 2015 Cost Estimates</th>
<th>Variance %</th>
</tr>
</thead>
<tbody>
<tr>
<td>705/709</td>
<td>WFEC/OGE</td>
<td>Gracemont Substation 345 kV</td>
<td>N/A</td>
<td>$8,000,000</td>
<td>$14,486,622</td>
<td>$14,486,622</td>
<td>0.0%</td>
</tr>
<tr>
<td>707/708</td>
<td>ITCGP/NPPD</td>
<td>Spearville - Post Rock - Axtell 345 kV</td>
<td>226.9</td>
<td>$236,557,015</td>
<td>$207,495,845</td>
<td>$207,495,845</td>
<td>0.0%</td>
</tr>
<tr>
<td>698/699</td>
<td>OGE/GRDA</td>
<td>Sooner - Cleveland 345 kV</td>
<td>36</td>
<td>$33,530,000</td>
<td>$50,262,358</td>
<td>$50,262,358</td>
<td>0.0%</td>
</tr>
<tr>
<td>702</td>
<td>KCPL</td>
<td>Swissvale - Stilwell Tap 345 kV</td>
<td>N/A</td>
<td>$2,000,000</td>
<td>$2,875,727</td>
<td>$2,875,727</td>
<td>0.0%</td>
</tr>
<tr>
<td>700</td>
<td>OGE</td>
<td>Seminole - Muskogee 345 kV</td>
<td>118</td>
<td>$129,000,000</td>
<td>$163,416,396</td>
<td>$163,416,396</td>
<td>0.0%</td>
</tr>
<tr>
<td>701/704</td>
<td>OGE/SPS</td>
<td>Tuco - Woodward 345 kV</td>
<td>290.1</td>
<td>$227,727,500</td>
<td>$330,003,491</td>
<td>$330,003,491</td>
<td>0.0%</td>
</tr>
<tr>
<td>703</td>
<td>GMO/KCPL</td>
<td>Iatan - Nashua 345 kV</td>
<td>30.9</td>
<td>$54,444,000</td>
<td>$62,949,252</td>
<td>$62,949,252</td>
<td>0.0%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>Total</strong></td>
<td>701.9</td>
<td><strong>$691,258,515</strong></td>
<td><strong>$831,489,691</strong></td>
<td><strong>$831,489,691</strong></td>
<td><strong>0.0%</strong></td>
</tr>
</tbody>
</table>
**PRIORITY PROJECTS**

In April 2010 the Board and Members Committee approved for construction a group of "priority" high voltage electric transmission projects estimated to bring benefits of at least $3.7 billion to the SPP region over 40 years. The projects issued NTCs as a result of the study are estimated to add 291 miles of new single circuit 345 kV transmission line and 435 miles of double circuit 345 kV transmission to the SPP region.

In October 2010 the Board approved an overall cost increase for the Priority Projects due to line rerouting and addition costs for reactive compensation. The total cost estimate for the Priority Projects after the variances were approved was $1.42 billion.

The total cost estimate for the projects included in the Priority Projects report did not change from the previous quarter total of $1.32 billion.

Figure 8 below depicts a historical view of the total estimated cost of the Priority Projects. Table 10 provides a project summary of the projects making up the Priority Projects. Table 11 lists construction status updates for the Priority Projects not yet completed.

![Figure 8: Priority Project Cost Estimate Trend](image-url)
### Table 9: Priority Projects Summary

<table>
<thead>
<tr>
<th>Project ID(s)</th>
<th>Project Owner(s)</th>
<th>Project Name</th>
<th>Est. Line Length</th>
<th>Board Approved Estimates (10/2010)</th>
<th>Q4 2015 Cost Estimates</th>
<th>Q1 2016 Cost Estimates</th>
<th>Var. %</th>
</tr>
</thead>
<tbody>
<tr>
<td>937</td>
<td>AEP</td>
<td>Tulsa Power Station 138 kV Reactor</td>
<td>N/A</td>
<td>$842,847</td>
<td>$614,753</td>
<td>$614,753</td>
<td>0.0%</td>
</tr>
<tr>
<td>940/941</td>
<td>SPS/OGE</td>
<td>Hitchland – Woodward District 345 kV Dbl Ckt</td>
<td>128.8</td>
<td>$221,572,283</td>
<td>$229,563,977</td>
<td>$229,563,977</td>
<td>0.0%</td>
</tr>
<tr>
<td>942/943</td>
<td>PW/OGE</td>
<td>Thistle – Woodward District 345 kV Dbl Ckt</td>
<td>106.6</td>
<td>$201,940,759</td>
<td>$185,687,533</td>
<td>$185,687,533</td>
<td>0.0%</td>
</tr>
<tr>
<td>945</td>
<td>ITCGP</td>
<td>Spearville – Ironwood – Clark Co. – Thistle 345 kV Dbl Ckt</td>
<td>122.5</td>
<td>$293,235,000</td>
<td>$318,138,968</td>
<td>$318,138,968</td>
<td>0.0%</td>
</tr>
<tr>
<td>946</td>
<td>PW/WR</td>
<td>Thistle – Wichita 345 kV Dbl Ckt</td>
<td>77.5</td>
<td>$163,488,000</td>
<td>$120,525,851</td>
<td>$120,525,851</td>
<td>0.0%</td>
</tr>
<tr>
<td>936</td>
<td>AEP</td>
<td>Valliant – NW Texarkana 345 kV</td>
<td>76.3</td>
<td>$131,451,250</td>
<td>$127,995,000</td>
<td>$127,995,000</td>
<td>0.0%</td>
</tr>
<tr>
<td>938/939</td>
<td>OPPD/TSMO</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (TSMO)</td>
<td>215.0</td>
<td>$403,740,000</td>
<td>$336,433,874</td>
<td>$336,433,874</td>
<td>0.0%</td>
</tr>
</tbody>
</table>

**Total** 726.7 $1,416,270,139 $1,318,959,956 $1,318,959,956 0.0%

### Table 10: Priority Projects Construction Status

<table>
<thead>
<tr>
<th>Project ID</th>
<th>Project Name</th>
<th>Projected In-Service Date</th>
<th>Engineering</th>
<th>Siting and Routing</th>
<th>Environmental Studies</th>
<th>Permits</th>
<th>Material Procurement</th>
<th>Construction</th>
</tr>
</thead>
<tbody>
<tr>
<td>936</td>
<td>Valliant – NW Texarkana 345 kV</td>
<td>10/1/2016</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
<td>IP</td>
</tr>
<tr>
<td>938</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (TSMO)</td>
<td>12/31/2016</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
</tr>
<tr>
<td>939</td>
<td>Nebraska City – Mullin Creek – Sibley 345 kV (OPPD)</td>
<td>12/31/2016</td>
<td>IP</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>IP</td>
<td>IP</td>
</tr>
</tbody>
</table>

**Table 10: Priority Projects Construction Status**
2012 ITP10

In January 2012 the Board approved the first Integrated Transmission Planning 10-Year Assessment (ITP10). The projects approved as a part of the report ranged from comprehensive regional solutions to local reliability upgrades to address the expected reliability, economic, and policy needs of the studied 10-year horizon. The approved portfolio from the 2012 ITP10 is expected to add approximately 513 circuit miles of new 345 kV transmission.

All the projects from the 2012 ITP10 are currently in the planning or construction phases. The first 2012 ITP10 project expected to complete is the new Matthewson 345 kV substation and second 345 kV circuit from Matthewson to Cimarron projected to be energized in July 2016.

Figure 9 below depicts a historical view of the total estimated cost of the 2012 ITP10 projects. Table 12 provides a summary of the projects approved as part of the 2012 ITP10.

Figure 9: 2012 ITP10 Cost Estimate Trend
<table>
<thead>
<tr>
<th>Project ID(s)</th>
<th>Project Owner(s)</th>
<th>Project</th>
<th>Est. 345 kV Line Length</th>
<th>Established Baseline Cost Estimates (Adj. for Inflation) Q4 2016</th>
<th>Q1 2016 Cost Estimates</th>
<th>Var. % (Q4 vs. Q1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>30361</td>
<td>AEP/OGE</td>
<td>Chisholm - Gracemont 345 kV</td>
<td>101.8</td>
<td>$175,481,866</td>
<td>$162,952,357</td>
<td>0.0%</td>
</tr>
<tr>
<td>30364</td>
<td>OGE</td>
<td>Woodward District EHV - Tatonga - Matthewson - Cimarron 345 kV Ckt 2</td>
<td>126.0</td>
<td>$191,915,155</td>
<td>$178,212,300</td>
<td>0.0%</td>
</tr>
<tr>
<td>30367</td>
<td>ITCGP/WR</td>
<td>Elm Creek - Summit 345 kV</td>
<td>58.2</td>
<td>$121,741,449</td>
<td>$118,814,429</td>
<td>-2.6%</td>
</tr>
<tr>
<td>30375</td>
<td>NPPD</td>
<td>Gentleman - Cherry Co. - Holt Co. 345 kV</td>
<td>227.0</td>
<td>$337,472,347</td>
<td>$313,376,623</td>
<td>0.0%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>513.0</strong></td>
<td><strong>$826,610,817</strong></td>
<td><strong>$773,355,709</strong></td>
<td><strong>-0.4%</strong></td>
</tr>
</tbody>
</table>

Table 11: 2012 ITP10
OUT-OF-BANDWIDTH PROJECTS

In adherence to the Business Practice 7060, SPP reports projects that have updated cost values that exceed their established baseline values based upon a ±20% bandwidth. Variances are determined by total project cost.

Two projects with a cost estimate greater than $5 million were identified as having exceeded the ±20% bandwidth requirement during the reporting period.

Table 13 provides summary information and Table 14 lists the cost detail for the out-of-bandwidth projects for Q1 2016.

<table>
<thead>
<tr>
<th>PID</th>
<th>Project Name</th>
<th>Owner</th>
<th>NTC Source Study</th>
<th>Upgrade Type</th>
<th>In-Service Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>938/939</td>
<td>Multi - Nebraska City - Mullin Creek - Sibley 345 kV</td>
<td>OPPD/TSMO</td>
<td>Priority Projects</td>
<td>High Priority</td>
<td>12/31/2016</td>
</tr>
<tr>
<td>30756</td>
<td>Multi - Battle Axe - Road Runner 115 kV</td>
<td>SPS</td>
<td>HPILS</td>
<td>High Priority</td>
<td>12/4/2015</td>
</tr>
</tbody>
</table>

Table 12: Out-of-Bandwidth Project Summary

<table>
<thead>
<tr>
<th>PID</th>
<th>Baseline Cost Estimate</th>
<th>Baseline Cost Estimate Year</th>
<th>Baseline Cost Estimate with Escalation</th>
<th>Latest Estimate or Final Cost</th>
<th>Variance</th>
<th>Variance %</th>
</tr>
</thead>
<tbody>
<tr>
<td>30756</td>
<td>$16,780,809</td>
<td>2014</td>
<td>$17,630,337</td>
<td>$11,250,000</td>
<td>($6,380,337)</td>
<td>-36.19%</td>
</tr>
</tbody>
</table>

Table 13: Out-of-Bandwidth Project Cost Detail
Table 15 and Figures 10 and 11 provide insight into the responsiveness of DTOs constructing Network Upgrades within SPP in the Quarterly Project Tracking Report for Q1 2016. **Note:** Network Upgrades with statuses of “NTC Suspension”, “Re-evaluation”, “Within NTC Commitment Window”, “Within NTC-C Project Estimate Window”, and “Within RFP Response Window” were excluded from this analysis.

<table>
<thead>
<tr>
<th>Project Owner</th>
<th>Number of Upgrades</th>
<th>Number of Upgrades Reviewed</th>
<th>Reviewed %</th>
<th>Number of ISD Changes</th>
<th>ISD Change %</th>
<th>Number of Cost Changes</th>
<th>Cost Change %</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>53</td>
<td>9</td>
<td>17%</td>
<td>4</td>
<td>7.5%</td>
<td>9</td>
<td>17.0%</td>
</tr>
<tr>
<td>BEPC</td>
<td>14</td>
<td>11</td>
<td>79%</td>
<td>11</td>
<td>78.6%</td>
<td>5</td>
<td>35.7%</td>
</tr>
<tr>
<td>GMO</td>
<td>3</td>
<td>3</td>
<td>100%</td>
<td>0</td>
<td>0.0%</td>
<td>2</td>
<td>66.7%</td>
</tr>
<tr>
<td>GRDA</td>
<td>12</td>
<td>2</td>
<td>17%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>ITCGP</td>
<td>9</td>
<td>7</td>
<td>78%</td>
<td>0</td>
<td>0.0%</td>
<td>4</td>
<td>44.4%</td>
</tr>
<tr>
<td>KCPL</td>
<td>6</td>
<td>4</td>
<td>67%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>LES</td>
<td>2</td>
<td>2</td>
<td>100%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>MIDW</td>
<td>13</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>MKEC</td>
<td>18</td>
<td>9</td>
<td>50%</td>
<td>5</td>
<td>27.8%</td>
<td>8</td>
<td>44.4%</td>
</tr>
<tr>
<td>NPPD</td>
<td>26</td>
<td>17</td>
<td>65%</td>
<td>7</td>
<td>26.9%</td>
<td>8</td>
<td>30.8%</td>
</tr>
<tr>
<td>OGE</td>
<td>55</td>
<td>28</td>
<td>51%</td>
<td>13</td>
<td>23.6%</td>
<td>13</td>
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Table 14: Responsiveness Summary by Project Owner
Figure 10: In-Service Date Changes by Project Owner

Figure 11: Cost Changes by Project Owner
APPENDIX 1

{See accompanying list of active Applicable Projects}
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<th>On Schedule beyond 4-year horizon (Date)</th>
<th>On Schedule within 4-year horizon (Date)</th>
<th>In-service and all required project close-out documentation supplied by TO</th>
<th>RTO Determined</th>
<th>Need Date</th>
<th>NTC Source Study</th>
<th>RE-EVALUATION</th>
<th>DELAY - MITIGATION</th>
<th>COMPETE</th>
<th>CURRENT COST</th>
<th>FINAL COST</th>
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**Notes:**
- The project statuses are based on the provided fields: "Completed," "Under Construction," or "On Schedule."
- The "Completed" status indicates that the project has been finished and is no longer under construction.
- The "Under Construction" status indicates that the project is currently in progress and may still be in the process of being completed.
- The "On Schedule" status indicates that the project is on track to be completed within the expected timeframe.

**Details:**
- The "Details" column contains additional information for each project, which may include contact information, project descriptions, or other relevant details.
- The "Cost" column reflects the budgeted costs for each project, with actual costs shown in parentheses where available.
- The "Completion Date" column indicates the expected date of completion for each project.

**Additional Information:**
- The "Timeline" column provides the duration of each project, from the start date to the end date.
- The "Project ID" column uniquely identifies each project.
- The "Source" column specifies the source of the project information, which may be "TWE" or another abbreviation.
- The "Type" column indicates the type of project, which may be "Construction" or another descriptor.

**Further Reading:**
For more detailed information on each project, please refer to the original source documents or contact the project managers directly.
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**Total Cost** includes any additional costs not captured in the primary data. **Current Cost** represents the most recent cost data available. **Percentage** indicates the completion status of the project. **Remarks** provide any additional notes or considerations related to the project.
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