REGULAR MEETING
Monday, April 21, 2008
1:00-5:00 p.m.
The Skirvin Hilton, Oklahoma City, OK

1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a quorum
   b. Adoption of January 28, 2008 Minutes

3. UPDATES
   a. RSC Financial Report
   b. Selection of Auditor for the Annual RSC Audit (Action Item) .......... Sam Loudenslager
   c. Other RSC officer reports
   d. FERC
   e. SPP
   f. RE

4. BUSINESS MEETING
   a. Cost Allocation Working Group ......................................................... Dr. Mike Proctor
      1. Revisions to the Base Plan Funding Policy for Wind
      2. Cost Allocation for Economic Upgrades
         • Tariff Language Development
         • Balanced Portfolio Development
   b. Initiatives on Seams Agreements, Balancing Authority Consolidation and Future Market Benefit/Cost Analysis ............................................................. Lanny Nickell
   c. OEPTTF and Updated EHV Reports .................................................. Jay Caspary
   e. Project Tracking (written report)

5. SCHEDULING OF NEXT REGULAR MEETING, SPECIAL MEETINGS OR EVENTS

6. ADJOURNMENT
Southwest Power Pool
REGIONAL STATE COMMITTEE
Doubletree Hotel at Warren Place
January 28, 2008
• M I N U T E S •

Administrative Items:
Members in attendance or represented by proxy were:
  Julie Parsley, Public Utility Commission of Texas (PUCT)
  David King, New Mexico Public Regulation Commission (NMPRC)
  Jeff Cloud, Oklahoma Corporation Commission (OCC)
  Jeff Davis, Missouri Public Service Commission (MPSC)
  Mike Moffet, Kansas Corporation Commission (KCC)
  Sam Loudenslager; for Colette Honorable, Arkansas Public Service Commission (APSC)

President Parsley called the meeting to order at 1:05 p.m. Cheryl Robertson (SPP) called roll and a quorum was declared. There were 69 in attendance (Attendance & Proxies – Attachment 1). Others in attendance via phone were: David Kays (OG+E).

President Parsley asked for adoption of the August 24 and October 29, 2007 meeting minutes (RSC Minutes 8/24/07 and 10/29/07 - Attachment 2). David King moved to approve the August and October minutes as presented. Jeff Davis seconded the motion. The minutes were approved unanimously.

President Parsley stated that FERC Commissioner Phillip Moeller and his aide Robert Ivanaukskas would join the meeting following a tour of ERCOT. The agenda will be changed in order to accommodate their late arrival.

Business Meeting
Cost Allocation Working Group Report

- Concepts Paper on Economic Upgrades
  Dr. Mike Proctor provided the Cost Allocation Working Group report (CAWG Report & Presentation – Attachment 3). Dr. Proctor reviewed the Concepts Paper on Economic Upgrades in SPP written for the purpose to outline the design for cost allocation of economic upgrades so that tariff language can be developed over the next few months. At the same time, SPP staff in support of the CAWG is to develop a draft balanced portfolio of economic projects in order to show how the process will work before filing with FERC. The cost allocation for economic upgrades will use the postage stamp rate design for extra high voltage (EHV) transmission upgrades of 345 kV or higher. A balanced portfolio will be screened by SPP to determine economic upgrades with benefits greater than costs over a ten-year period. Dr. Proctor offered the following recommendation: The CAWG recommends that the SPP RSC adopt the Concepts Paper for Economic Upgrades for purposes of implementation by the SPP RTO. David King moved to adopt the concepts paper as presented. Jeff Davis seconded the motion, which passed unanimously.
Regional State Committee  
January 28, 2008

- **Wind Generation Base Plan Funding Policy Discussion**
  Larry Holloway provided a report regarding wind and Base Plan funding (Wind Report – Attachment 4). Mr. Holloway reviewed the treatment of wind generation under the current Tariff, why wind may be treated differently than other resources in terms accredited capacity and presented alternatives for consideration. It was concluded that an alternate Cost Allocation Plan (CAP) for wind generation supplying SPP load needs to be developed.
  **Mike Moffet moved to include the CAP for wind generation in the work plan. David King seconded the motion, which passed unanimously.** President Parsley requested that Mr. Holloway or another person present a plan on cost methodology for wind at the April RSC meeting.

- **2008 Work Plan**
  The CAWG Work Plan was reviewed (Work Plan – Attachment 5).

- **Empire District Electric Waiver Request**
  Dr. Mike Proctor provided background for the Empire District waiver request (Empire Waiver – Attachment 6). Dr. Proctor pointed out that the waiver request had been delayed until better figures were available. Costs have come down as the EDE projects continue to be restudied as a part of the ongoing Aggregate Study process coupled with the fact that the RSC appears to be about to make policy changes for wind as illustrated by Mr. Holloway’s presentation and the CAWG as well as the Markets and Operations Policy Committee (MOPC) recommends that the RSC and the SPP Board of Directors approve the Empire District waiver for full base plan funding. **Mike Moffet moved to approve the Empire waiver. Jeff Davis seconded the motion, which passed unanimously.**

**FERC Update**
Commissioner Philip Moeller joined the meeting and was asked to share comments with the group. Commissioner Moeller expressed his thanks to Dr. Proctor for all his good work, appreciation for the RTO effort and noted that he operated with an open door policy welcoming emails and phone calls. He applauded the group for passing the Concept Paper for Economic Upgrades and stressed that we need to build transmission sooner than later. Commissioner Moeller stated that with the reappointments of Commissioners Kelliher and Wellinghoff, the Commission is able to offer stability for a measurable length of time. A major issue throughout the country today is FERC exercising its penalty authority as the reliability standards kick in and the battle of benefits and competition.

John Rogers provided an update on FERC activities:
- The Commission issued a Notice of Proposed Rulemaking proposing changes to the principal financial forms for electric utilities and licensees. The proposed effective date for these changes will be the calendar year 2009. Comments are due 45 days after publication in the Federal Register.
- The Commission approved eight new critical infrastructure protection reliability standards to protect the nation’s bulk power system against potential disruptions from cyber security breaches. The mandatory reliability standards require certain users, owners and operators of the bulk power system to establish policies, plans and procedures to safeguard physical and electronic access to control systems, to train personnel on security matters, to report security incidents, and to be prepared to recover from a cyber incident.
- The Commission conditionally accepted Duquesne’s exit from the PJM RTO. Duquesne plans to withdraw from PJM effective May 31, 2008, if he is able to join the Midwest Independent System Operator. The Commission approved the withdrawal subject to a compliance filing and Duquesne meeting certain obligations.

In December, the Commission issued a rehearing order on Order No. 890, largely reaffirming the findings in Order No. 890.

The Commission recently issued two orders involving SPP. The Commission accepted in part and rejected in part a recent SPP filing regarding its Large Generator Interconnection Procedures and Interconnection Agreement and directed a compliance filing. The Commission also issued an order on SPS, OG&E and
Regional State Committee
January 28, 2008

AEP’s application to terminate their purchase obligations from Qualifying Facilities under PURPA. The Commission granted OG&E and AEP’s requests and denied SPS’s request without prejudice.

John introduced Commissioner Moeller’s aide, Robert Ivanauskas, and Patrick Clarey (FERC) noting that Patrick is acting in an outreach capacity to the Midwest ISO and SPP.

AEP Waiver
Dr. Proctor then provided background for the American Electric Power waiver (AEP Waiver Request – Attachment 7). The AEP waiver was for costs in excess of the Safe Harbor Cost Limit for Base Plan funding. It is the recommendation of the MOPC that the SPP Board of Directors approve 100% the AEP waiver for such amount to fully Base Plan fund the project. Jeff Davis moved to approve the AEP waiver as requested. David King seconded the motion, which passed with Sam Loudenslager abstaining.

Overview of Board of Directors and Stakeholders Survey
Michael Desselle provided a review of the SPP Stakeholders and SPP Board of Directors Surveys. This is the second year of the SPP Stakeholder Survey. Many categories were above the mid point including meeting logistics and the Energy Imbalance Market showed significant improvement. Two areas in need of improvement were: transmission planning and Tariff administration. There is an action plan under development to improve stakeholder satisfaction.

The SPP Board of Directors Survey was conducted for the third time. Five of twelve items showed significant improvement and other results were not significantly different. The Strategic Planning Committee has developed an action plan/straw proposal to get feedback for going forward.

STEP 2007, OEPTTF and EHV Report
Jay Caspary provided a presentation regarding the SPP Transmission Expansion Plan (STEP), the Oklahoma Electric Power Transmission Task Force (OEPTTF) study, and the Extra High Voltage (EHV) report (STEP, OEPTTF, EHV Presentation – Attachment 8). The STEP 2008-2017 includes $2.2 billion of transmission projects. The MOPC will present this plan to the SPP Board of Directors for approval on January 29. The OEPTTF approved a Scope in December and hopes to finalize a study in the first quarter of 2008. Mr. Caspary reviewed the EHV Overlay Study completed in 2007 and a restudy where results are expected in the first quarter of 2008. He also provided information on the Joint Coordinated System Plan (JCSP) with MISO, PJM, TVA and others. Joint Operating Agreements require development of joint plans every few years.

EPRI Report – The Power to Reduce CO2 Emissions Highlight
Les Dillahunty provided a report on reducing CO2 emissions (Power to Reduce CO2 Emissions – Attachment 9). The full report is published on the EPRI website.

Project Tracking (written report)
The SPP First Quarter 2008 Project Tracking Report and the 2007 STEP Project Tracking Summary were provided for review (Project Tracking – Attachment 10).

RSC Financial Update
Les Dillahunty (SPP) presented the RSC Financial Report (RSC Financial Report – Attachment 11). Mr. Dillahunty reported that the RSC remained well under budget for 2007. An RFP was sent to vendors on Friday regarding bids for a cost benefit study associated with the possible expansion of SPP markets.

Sam Loudenslager reported that the Customer Response Task Force (CRTF) working under the Market Working Group in regard to the current Energy Imbalance Market has arranged for Berkeley Labs to perform a Demand Response Survey for SPP as they have done for the Midwest ISO. Results will be ready for a Demand Response Forum tentatively scheduled before the July meeting. Members will be surveyed in March as to what they are doing in regards to the Demand Response and Energy Efficiency issues. The results will be provided to the RSC and SPP. Mr. Loudenslager encouraged a good response to this effort in order to get good information. The RSC was asked to consider a Demand Response workshop at the July meeting at which time survey results could be reported. The RSC will make this decision in April.
SPP Update
Nick Brown congratulated the RSC for its great work in adopting the Concept Paper for Economic Upgrades and stated that it was cause for celebration.

In looking forward:
- The Strategic Planning Committee has started a process of strategic initiatives. Organizational groups will provide input and the RSC is invited to suggest projects to be in the front and center of these initiatives. The current plan recognizes the importance of communication with policy makers to realize transmission expansion. Working closely with state regulators to reach and educate groups is critical to the actual expansion.
- SPP is also reviewing the committee structure working with members to ease the burden of the number of meetings.
- The EPRI PRISM as presented by Mr. Dillahunty offers a strong portfolio approach and it will take all initiatives to achieve the desired outcome.
- Mr. Brown announced that Quentin Jackson, SPP Director, will be leaving the Board of Directors following tomorrow’s meeting. He provided excellent service to the Board and will be missed.

SPP Regional Entity Trustees
President Parsley asked John Meyer, Chair of Regional Entity Trustees (RET), to provide an update of the group’s activities. Mr. Meyers deferred to Michael Desselle. Mr. Desselle provided a report regarding violation updates stating that there had been 164 self reported violations to date. After June 18 the process will be slower as violations are confidential until filed at FERC. Three member audits have been performed since June reporting no violations. A Compliance Workshop was held last week in Tulsa and was a great success. Currently the group is working on the new Regional Standard under development, Under Frequency Load Shedding.

Scheduling of Next Regular Meeting, Special Meetings or Events:
President Parsley noted that the next regularly scheduled RSC meeting is in Oklahoma City on April 21, 2008. In the event of a called teleconference regarding Tariff language, the group will be given a one week notice.

With no further business, the meeting was adjourned.

Respectfully Submitted,

Les Dillahunty
## Regional State Committee
### For the Three Months Ending March 31, 2008
#### Budget vs. Actual

**DRAFT**

<table>
<thead>
<tr>
<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
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</table>

### Income

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<th>Description</th>
<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
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<tbody>
<tr>
<td>Other Income</td>
<td>14,543</td>
<td>279,361</td>
<td>(264,818)</td>
</tr>
<tr>
<td><strong>Total Income</strong></td>
<td><strong>14,543</strong></td>
<td><strong>279,361</strong></td>
<td><strong>(264,818)</strong></td>
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### Expense

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<tr>
<td>Travel</td>
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<td>Meetings</td>
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<td>13,200</td>
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<td>Audit</td>
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<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Administrative Costs</td>
<td>112</td>
<td>375</td>
<td>(263)</td>
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<tr>
<td>Cost Benefit Studies</td>
<td>-</td>
<td>249,286</td>
<td>(249,286)</td>
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<tr>
<td><strong>Total Expense</strong></td>
<td><strong>14,543</strong></td>
<td><strong>279,361</strong></td>
<td><strong>(264,818)</strong></td>
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### Net Income (Loss)

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<th>YTD Actuals</th>
<th>YTD Budget</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Income (Loss)</strong></td>
<td><strong>-</strong></td>
<td><strong>-</strong></td>
<td><strong>-</strong></td>
</tr>
</tbody>
</table>

(A) YTD revenue is less than budget given that ytd expenses are less than budget.
(B) YTD study costs are less than budget as no studies have been conducted in 2007.
Proposals for Cost Allocation of Designated Wind Resources

Presentation by CAWG
To SPP RSC
April 21, 2008

Background: The Problem

Current cost allocation for upgrades for Designated Wind Resource requests for transmission service is detrimental to:

1. Requestor by restricting safe-harbor calculations to 10% of Requested Transmission Capacity.
2. Non-sink zones by allocating 67% of upgrades in these zones using a MW-mile allocation.

Background: The Proposals

• At the January CAWG meeting Larry Holloway presented a proposal, and at the February CAWG meeting Mike Proctor presented a proposal. Others were asked to bring proposals to the March CAWG meeting. Larry and Mike worked together on a Compromise proposal.

• At the March 26 CAWG meeting 4 proposals were presented to the CAWG:
  1. Compromise Proposal
  2. TO Proposal
  3. OGE Proposal
  4. TDU Proposal

• All four proposals agree on some basic aspects of solving the problems:
  - The Safe Harbor of $180,000/MW for wind resources should use the Requested Transmission Capacity (100%), not the accredited capacity at time of summer peak (10%).
  - This cost allocation provisions for Designated Wind Resources should be limited by the operational restrictions that too much wind capacity could place on the SPP power grid.

• The CAWG reviewed the remaining differences in these proposals via teleconference calls on April 3 and 17.

Background: Narrowing Alternatives

The CAWG has eliminated two proposals as not being appropriate interim solutions to the problem:

1. The OGE proposal is: 1) to continue with the existing cost allocation for upgrades below 300 kV; but 2) to allocate upgrades above 300 kV on a load-ratio share basis by including the revenue requirements for these upgrades in a region-wide (postage stamp) rate.
   • CAWG will fully consider this proposal in its review of the entire Base Plan Funding process, but this review is more comprehensive and would take more discussion than is available to meet our April deadline.

2. The TDU proposal is to allocate all upgrade costs associated with a Designated Wind Resource on a load-ratio share basis by including the revenue requirements for these upgrades in a region-wide (postage stamp) rate.
   • CAWG believed that for this proposal to be appropriate for the SPP region would require a region-wide adoption of a Renewable Portfolio Standard, or at least having each state within the region adopt similar Renewable Portfolio Standards.

Background: Similarities in the Remaining Proposals

The Compromise Proposal and TO proposal agree on basic points regarding beneficiaries:

1. The Sink Zone is the zone in which the load of the requestor is located. The CAWG and TOs agree that the costs of upgrades in the sink zone should be allocated using the current method: 1/3 postage stamp and 2/3 MW-mile.
   • All transmission customers in and around the sink zone will benefit on a sub-regional basis from the upgrades in the sink zone, and this benefit is appropriately taken into account through the MW-mile allocation methodology.

2. The Non-Sink Zone costs of upgrades assigned to the requestor should not receive a MW-mile allocation. This resolves the second problem of benefit to both the supply zone in which the wind is located and the "pass-through" zones, both of which may require upgrades to deliver from the supply zone to the sink zone.
   • The transmission customers in and around the non-sink zones will not benefit on a sub-regional basis from upgrades needed for delivering wind power to other zones. Moreover, the MW-mile allocation is not an appropriate indicator of beneficiaries for these type of upgrades.

Background: Modifying Proposals

At the April 4 CAWG Teleconference, the CAWG agreed to adopt certain changes:

1. Safe-harbor calculations limiting Base Plan Funding to $180,000/MW would be applied to all of the costs assigned to the transmission request, and not be limited to only costs assigned to the transmission request from upgrades in the sink zone.

2. Removal of having a limit (cap) on the percent of total costs that could be directly assigned to the requestor, and instead treat this issue through waiver requests. However, there is still some concern regarding the removal of a cap of 1/3 of total upgrade cost that can be directly assigned to the requestor even with the possibility of waiver requests.
Background: Applying the Proposals

• At the April 17 CAWG teleconference call, SPP staff made a presentation that applied the current cost allocation along with the four proposals to actual requests.
• Clarifications of the presentation were discussed at that meeting, and the SPP staff will update its calculations and present the updated results at the April 30 CAWG meeting.

Two Differences in Proposals

• How the costs of the upgrades in the non-Sink zone should be divided between a postage stamp rate and directly assigned to the requestor:
  – Compromise: 1/2 postage stamp and 1/2 direct assignment
  – TO Proposal: keep the original cost allocation of 1/3 postage stamp, but replaced the 2/3 MW-mile allocation with 1/2 postage stamp and 1/2 direct assignment. Combining these two results in 2/3 postage stamp and 1/3 direct assignment.
• Whether the limit placed on the Designated Wind Resources should be 20% of Forecasted Summer Peak or 20% of Designated Resource Net Capacity:
  – Various states agreed at the April 17 meeting to stick with 20% of forecasted summer peak. This corresponds to a Renewable Portfolio Standard of approximately 15% energy from renewable sources.
  – It was noted that DOE is doing a wind integration study that includes the SPP, and when that study is completed (June, 2009) we will want to revisit this limit.

Implications from the Two Proposals

The impacts shown below are for a specific example that may or may not be representative of a "typical" request for Designated Wind Resource

Going Forward

• Feedback from RSC: Is the CAWG heading in the right direction?
  – Considering Only the Compromise vs. TO proposals at this time
• The RSC could vote today on which of the two proposals Compromise vs. TO it prefers.
  – While we have not had time to discuss the full details of the SPP updated results, the impacts on the Compromise vs. TO proposals will be on the difference in the allocation of Non-Sink Zone Costs.
• The RSC could delay a vote until after the April 30 CAWG meeting.
  – At that time the CAWG will have had time to consider and discuss the full details of the SPP updated results. This will allow more time to consider the impacts of the differences in the allocation of Non-Sink Zone Cost.
  – A major change in the updated results is the difference between the allocation of Non-Sink Zone Costs between the Compromise and TO proposals.
Update on Balanced Portfolio of Economic Upgrades: Tariff Language Development Portfolio Selection Process

Report to SPP RSC
April 21, 2008

Tariff Language Development

- SPP has asked Accenture (Mark Rossi and Pam Kozlowski) to develop proposed tariff language.
- The proposed tariff language is under review by the RTWG
  - March 17 Teleconference Call
  - March 26 RTWG Meeting
  - April 7 Teleconference Call
  - April 18 Teleconference Call

Progress Is Being Made

- The tariff is impacted in several places, but most importantly in:
  - Attachment O: Transmission Planning
  - Attachment J: Cost Allocation
- **Attachment O** tariff changes have been reviewed and are close to being finalized.
- **Attachment J** tariff changes (for all but one key element) are under review and are also close to being finalized.
- **Key Element** is the tariff language for implementing the transfer of costs from the zonal rate to the region-wide rate required to balance an unbalanced portfolio.
  - RTWG set up a separate task force to work on this question.
  - That task force met on April 18 (after this presentation was written). Verbal update on the results from that meeting.

Portfolio Development

- SPP staff is continually working on the development of alternative portfolios for stakeholder evaluation.
- Each month the CAWG is given an update on portfolio development that includes alternative portfolios of economic upgrades that appear to meet the requirement that benefits to load in the SPP region exceed costs.

Overview of Portfolios

- SPP has presented four such portfolios along with estimates of benefits by SPP zones.
- The following slides that are selected from a presentation made by Charles Cates (SPP staff) at the February CAWG meeting are meant to give the RSC a general sense of what is being considered.
  - The complete set of SPP slides can be found on the SPP website under CAWG documents from the February meeting.
  - All portfolios are tentative and all results are preliminary.

Economic Portfolio Project Selection Process

- The project selection process in the Economic Portfolio is based off of the 2012 Spring and Summer economic project screening
- In general, projects with a higher individual B/C ratio were given preference over projects with lower B/C ratio
- SPP has assembled four initial portfolios and conducted adjusted production cost analysis for these portfolios
- Comprehensive analysis performed using PROMOD and is simulated for an entire year (3/1/2012 through 2/28/2013) on every hour.
## Portfolio Costs and B/C Ratios

<table>
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<th>Portfolios</th>
<th>Cost ($M)</th>
<th>B/C Ratio</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>520.7</td>
<td>1.3</td>
</tr>
<tr>
<td>2</td>
<td>371.0</td>
<td>1.7</td>
</tr>
<tr>
<td>3</td>
<td>346.6</td>
<td>2.6</td>
</tr>
<tr>
<td>4</td>
<td>608.4</td>
<td>1.5</td>
</tr>
</tbody>
</table>

Portfolio 3 has the highest benefit to cost ratio and also was designed to be the most balanced of the four portfolios.

## Next Steps

- Develop further year cases for analysis: 2012, 2017, 2022
- Develop futures cases (e.g. high wind, carbon regulation, etc)
- Finalize group of portfolios to use for the above analysis
- Stakeholder buy in and feedback

The CAWG will have an update on next steps that have been completed for portfolio development at its April 30 meeting.
Helping our members work together to keep the lights on... today & in the future
Overview

• Oklahoma Electric Power Transmission Task Force (OEPTTF)
• 2008 EHV Overlay Study
• Joint Coordinated System Plan (JCSP)

OEPTTF Study

• Oklahoma Electric Power Transmission Task Force (OEPTTF) created by OK legislature
• Identify need for SPP study to identify transmission expansion needs for OK and beyond
• Scope and assumptions approved late December, 2007
• Final Report posted March 31, 2008
OEPTTF Base Wind Assumptions (MWs)
In-Service + On Schedule + 50% Suspension

<table>
<thead>
<tr>
<th>Wind Status</th>
<th>Base Wind</th>
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<tbody>
<tr>
<td><strong>Kansas</strong></td>
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<tr>
<td>In-Service</td>
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<tr>
<td>On Schedule</td>
<td>750</td>
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<tr>
<td>Suspension (50%)</td>
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<tr>
<td><strong>Oklahoma</strong></td>
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<tr>
<td>In-Service</td>
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<tr>
<td>On Schedule</td>
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<td>Suspension (50%)</td>
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<tr>
<td><strong>N. Mexico / Texas</strong></td>
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<tr>
<td>In-Service</td>
<td>605</td>
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<tr>
<td>On Schedule</td>
<td>654</td>
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<tr>
<td>Suspension (50%)</td>
<td>240</td>
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<tr>
<td><strong>Total</strong></td>
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OEPTTF Total Wind Assumptions (MWs)

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<thead>
<tr>
<th></th>
<th>Nominal Wind</th>
<th>High Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2010</td>
<td>2020</td>
</tr>
<tr>
<td><strong>In-Service + On Schedule + 50% Suspension</strong></td>
<td>4,050</td>
<td>4,050</td>
</tr>
<tr>
<td><strong>Additional Wind</strong></td>
<td>3,500</td>
<td>7,000</td>
</tr>
<tr>
<td><strong>Grand Total Wind</strong></td>
<td>7,550</td>
<td>11,050</td>
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</table>
OEPTTF Economic Analysis - Results

- Transmission expansion required to provide firm deliveries for 345 kV build out virtually eliminate all existing flowgate constraints in SPP saving $100 – 300 M / year in adjusted production costs
- New flowgates in / around SPP = ?
- Revenues for wind energy payments and collector system fees are remarkable
  1. Wind Revenues for 15,000 MW = $2.4B / year
  2. Collector System Fees are $300 – 600M / year
OEPTTF Economic Analysis - Project Costs

- Total Estimated Cost of Projects:
  1. 345 kV option = $4.5 Billion
  2. 765 and 345 kV alternative = $3.4 Billion
- 765 and 345 kV alternative warrants serious consideration

Updated EHV Overlay Study

- Analysis of Alternative 5 from original study does not support 345 kV build out
- Soliciting input from stakeholders on results to date, issues, concerns at [ehvoverlay@spp.org](mailto:ehvoverlay@spp.org)
- Results expected 2nd Quarter 2008
New Wind in Updated EHV Overlay Study

- Kansas: 6,600 MW (31.9%)
- Missouri: 750 MW (3.6%)
- New Mexico: 300 MW (1.4%)
- Oklahoma: 8,550 MW* (41.3%)
- Texas: 4,500 MW (21.7%)

**TOTAL**: 20,700 MW (100%)

* Includes 4,450 MW in Oklahoma Panhandle

Potential EHV Overlay Mid-Point Design for 13.5 GW Wind
Updated EHV Overlay Study Findings

Focus on midpoint designs to collect / deliver 13.5 GW of new wind in SPP
- 5.5 GW to SPP
- 3 GW to WECC via HVDC
- 2.5 GW to northeast
- 2.5 GW to southeast

$8 billion at $2 million / mile engineering and construction costs + $65,000 / mile for Rights-of-Way
- 2,250 miles of 765 and 500 kV in SPP
- Almost 600 miles of 765 kV in new interconnections and connectivity in neighboring systems

Updated EHV Overlay Study Findings

- Identifying phasing of build outs for alternatives
- Long term EHV Overlay needs to compliment interregional and coordinated planning efforts with:
  - Joint Coordinated System Plan (JCSP)
  - Entergy
  - Nebraska
  - Associated Electric Cooperative Inc
  - Electric Reliability Council of Texas
  - Western Electricity Coordinating Council
Construction Sequence: Package 1

Package 1: Step 1
Package 2: Step 2

Package 1: Step 3
Construction Sequence: Package 2

Construction Sequence: Phase 3
Possible Long Range Design (10+ GW Export EI)

Updated EHV Overlay Plan Next Steps

- Summit 3/28 - Oklahoma City Cox Convention Center
- Study materials posted at www.spp.org
- Finalize alternatives
- Conclude economic analyses
- Complete Updated EHV Overlay Plan
- Obtain approvals on plan and address barriers to implementation
  - Cost Allocations / Seams Agreements
  - Communications Plan
  - Determine 765 kV design standards
  - Other?
Reconciling Long Range Plans

OEPTTF - $3.4B
- 765 and 345 kV alternative in 2020 focusing on SPP upgrades only assuming ICT Strategic Transmission Expansion Plan (ISTEP) in Entergy

Updated EHV Overlay Study - $8B
- 765 and 500 kV in 2027 considering SPP plus Tier 1 and Tier 2 upgrades
Wind Integration Issues

Operational issues / reliability concerns warrant further investigation to address wind integration challenges
- Lower voltage injections / collector systems
Further dynamics and reactive compensation analyses
SPP staff / members involved in numerous industry initiatives on wind integration
EHV build out, regardless of drivers, will require changes to power system planning and operations

Joint Coordinated System Plan

- Collaborative effort by MISO, PJM, SPP and TVA initiated with kickoff meeting November 1 in Pittsburgh
- SPP representing RTO, plus Entergy ICT and LGE Energy ITO
- TVA representing Central Public Power Partners including AECI, BREC & EKPC
- NYISO and ISO-NE are engaged now
- Interested expressed by Duke and others at recent Southeast Inter-Regional Planning Process meetings in Charlotte
JCSP Next Steps

- Economic Transmission Fundamentals Workshop April 29-30 Charleston SC
- Regional workshops to follow in June-July, tentative St Louis, Knoxville, Boston and Wilmington
- Evaluate 20% National RPS as part of 2008 NREL/DOE Eastern Wind Integration and Transmission Planning Study
- Foundation for NERC LTRA Scenario and next DOE Congestion Study due August 2009
Questions?

Jay Caspary
Director, Engineering
501.614.3220
jcaspary@spp.org

www.spp.org
Southwest Power Pool
Strategic Planning Committee’s
Customer Response Task Force

CHARTER

Purpose
The Customer Response Task Force (CRTF) is directed to pursue and complete several specific initiatives as delineated in the Scope. Further, the CRTF is to coordinate its activities and investigations with the SPP Market Working Group Demand Response Task Force (DRTF).

Scope of Activities
In carrying out its purpose, the CRTF will:

1. Conduct a "State-of-the-art" (within SPP) DR/EE survey & dissemination of such**;
2. Provide for Member education as to potential benefits and institutional barriers**;
3. Conduct an analysis of the discontinuities between wholesale and retail markets as to DR/EE; and
4. Conduct an analysis of the interplays of DR/EE with performing future benefit/cost analyses.

CRTF Roster
Billy Berny (AEP) - (Chairman)
Bill Wylie (SPP) - (Secretary)
Denise Bode - (Member)
Adrienne Brandt (TPUC) - (Member)
Kelly Champion (AEP) - (Member)
Joyce Davidson (OCC) - (Member)
Gary Marchbanks (OGE) - (Member)
Jason Jones (KCPL) - (Member)
Paul Lehman (XCEL) - (Member)
Sam Loudenslager (APSC) - (Member)
Joseph O'Donnell (KCPL) - (Member)
George Phillips (KCPL) - (Member)
Nicholas Planson - (Member)
Roger Powell (KCPL) - (Member)
Gerrud Wallaert (SPP) - (Member)
Sherry McCormack (EDE) - (Member)
Paula Carvell (WESTAR) - (Member)

**Documents following are implementations of these two steps.
Lawrence Berkeley National Laboratory (LBNL) has been asked by the Customer Response Task Force of the SPP Strategic Planning Committee to conduct a survey of retail demand response programs and tariffs in the Southwest Power Pool footprint. The purpose of the survey is to create a comprehensive inventory of retail DR programs and dynamic pricing tariffs within the region. Survey results will be used to characterize the DR resources available, inform the regional state committee on the status of DR in the region, and identify barriers to DR in wholesale and retail markets.

LBNL has already fielded a DR program survey to all fifty SPP Members, including Cooperatives, Independent Power Producers, Independent Transmission Companies, Investor-owned utilities, Marketers, Municipalities, and State Agencies. The additional questions provided below are targeted especially to load-serving entities engaged in managing demand response programs and dynamic pricing tariffs.

Your feedback is valuable to us and will help ensure that LBNL’s report to your Strategic Planning Committee reflects the current status and latest developments for demand response resources. Please take a few minutes to familiarize yourself with the questions below ahead of the scheduled telephone interview.

1. Please verify the contact information we have for you

   **Name:** 
   **Organization:** 

   **Title:**

   **Organization Type (cooperative, IOU, municipality, aggregator, etc.)** 

   **Location:**

   **Phone:** 
   **Fax** 
   **E-mail:**

2. We would like to capture your recent experience with barriers that affect your ability to develop, market and operate demand response programs. What are the most significant barriers to scaling-up the use of demand response in the SPP region?

   **Customer Participation** 
   **Utility management support** 
   **Technical Issues**

   **Regulatory support & acceptance**
   **Uncertainties about the value of DR**
   **Cost**

   **Other (please specify):** ____________________________________________________________________________

   Please describe the biggest barriers and how they’ve affect DR development

3. Our experience elsewhere has been that dynamic pricing tariffs have their own unique set of
challenges. Based on your experience as a manager charged with developing dynamic pricing tariffs, what are the most significant barriers you've encountered?

Customer Participation  □  Regulatory support & acceptance  □
Utility management support  □  Uncertainties about the value of DR  □
Technical Issues  □  Cost  □
Other (please specify): ____________________________________  □
Not applicable (our utility has not implemented a dynamic pricing tariff): ______  □

Please describe the biggest barriers and how they’ve affect development of dynamic pricing.

4. Drawing on your experience in marketing DR and dynamic pricing programs, please indicate any customer reactions or aspects of the program which created difficulties;

Potential benefits don’t justify the risks  □  Penalty is too severe  □
Payments are too low  □  Unable to shift usage  □
Program complexity  □  Need to purchase equipment  □
Program conflicts with my retail electricity rate or contract  □
Inadequate knowledge of program requirements and benefits  □
Others (please specify)

5. What do you see as the major retail/wholesale issues affecting scaling-up use of DR in the SWPP Region?

Opportunities for DR resources in SPP wholesale markets & operations  □
Retail DR program design doesn’t suit the needs of SWPP dispatchers  □
State regulators won’t approve tariff changes needed  □
Incentives and compensation for customers isn’t sufficient  □
Other (Please describe)

What can the Customer Response Task Force of the SPP Strategic Planning Committee do to help overcome these barriers?
6. Compensation is always a key issue for DR programs. We would like to know more about the criteria that you use to establish a demand response payment system. Please describe the basis for and calculation of compensation for participants in DR programs.

*In what form is compensation provided?*

- Capacity payments [ ]
- Energy Payments [ ]
- Both [ ]

*If you provide capacity payments, what is the basis for the credits or discounts?*

- Long-term Marginal capacity costs [ ]
- Peaking unit proxy [ ]
- Value of un-served energy [ ]
- Improved Reliability [ ]
- Other (Please Specify) [ ]

Please specify Average Capacity Credits: __________$/kW-year

*To the extent you provide additional compensation in the form of energy payments, what is the basis for such payments?*

- Short-term marginal energy costs [ ]
- Power procurement contracts [ ]
- Day-ahead energy market prices [ ]
- Other (specify) [ ]

*Is there a threshold price at which your utility decides to call demand response resources to curtail loads? If so, please specify this “strike price”:*

- $0-$49/MWH [ ]
- $50-$200/MWH [ ]
- $201-$499/MWH [ ]
- $500-749/MWH [ ]
- $750-$999/MWH [ ]
- $1,000/MWH & over [ ]

*What is the relationship between actual cost savings and participant compensation? Are savings “shared” between the program operator and the program participant? If so, please approximate the “Savings Shared Percentage” that flows from program operator to program participant:*

- 0-25 % [ ]
- 25-50% [ ]
- 50-75% [ ]
- 75%-100% [ ]
- Not Applicable [ ]

New demand response concepts and technologies are emerging and evolving. Please provide your feedback and describe your efforts and activities in the following areas.

7. Using DR to manage network congestion, local constraints, rapid load growth or substation overloads.

*Is this an area your utility is active in?* Yes [ ] No [ ]

*If yes, please describe the types of DR programs being used:*
Notable Results to date:

8. Coordination of demand response and energy efficiency programs

Is this an area your utility is active in? Yes ☐ No ☐

If yes, please describe your coordination efforts and activities:

Notable Results to date:

9. What are your future plans for your DR programs and dynamic pricing tariffs? Do you expect to add additional programs or expand existing programs significantly? Which areas in your thinking are the most promising, and how will these new programs affect regional system operations and wholesale market development?
Survey Contact Information
(For Questions & Clarifications on your survey response)

SPP Member Information

Company Name:
Company Location (State):
Type of Organization:

Emergency DR Program Manager

Name:
Title:
Email Address:
Phone #:

Dynamic Pricing Tariffs Manager

Name:
Title:
Email Address:
Phone #:

Voluntary Demand Response Program Manager

Name:
Title:
Email Address:
Phone #:

Follow-up Interview Contact Information
(Please designate one individual)

Name:
Title:
Email Address:
Phone #:
<table>
<thead>
<tr>
<th>DEMAND RESPONSE PROGRAMS</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Demand response programs and tariffs include interruptible/curtailable tariffs, direct load control, emergency DR programs and demand bidding programs. These programs can be &quot;triggered&quot; for either emergency or economic (high price) reasons. If there is more than one type of Demand Response Program that is offered to various customer groups/classes, please fill out one column for each program.</td>
<td></td>
</tr>
</tbody>
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<table>
<thead>
<tr>
<th>4 General Program Information</th>
<th>Program 1</th>
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</thead>
<tbody>
<tr>
<td>PROGRAM ADMINISTRATOR (Cooperative, IPP, ITC, IOU, Marketeer, Municipal, State Agency)</td>
<td></td>
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<tr>
<td>PROGRAM NAME</td>
<td></td>
</tr>
<tr>
<td>OPERATIONAL TRIGGER</td>
<td></td>
</tr>
<tr>
<td>PROGRAM AVAILABILITY (e.g., summer or winter seasonal, year round)</td>
<td></td>
</tr>
<tr>
<td>PROGRAM DOCUMENTATION: Has the program been evaluated or reported on recently? Are results publicly available? If so, please provide references.</td>
<td></td>
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<table>
<thead>
<tr>
<th>Eligibility Requirements</th>
<th></th>
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<tbody>
<tr>
<td>MINIMUM SIZE REQUIREMENTS: Please specify any threshold conditions for participation</td>
<td></td>
</tr>
<tr>
<td>- Customer peak demand (kW) or Consumption (kWh)</td>
<td></td>
</tr>
<tr>
<td>- Size of Load Reduction (kW)</td>
<td></td>
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<tr>
<td>- Voltage level</td>
<td></td>
</tr>
<tr>
<td>- Other (Please describe)</td>
<td></td>
</tr>
<tr>
<td>CUSTOMER TYPE: Please specify any market segment eligibility requirements</td>
<td></td>
</tr>
<tr>
<td>- Residential</td>
<td></td>
</tr>
<tr>
<td>- Commercial</td>
<td></td>
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<tr>
<td>- Industrial</td>
<td></td>
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<tr>
<td>- Other (Please describe)</td>
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</tbody>
</table>

| PROGRAM EXCLUSIVENESS: Can participants simultaneously participate in other DR, demand bidding, or dynamic pricing programs? (Yes or No) |  |
| Program exclusive? |  |

| ON-SITE GENERATION: Is Onsite Generation eligible to participate in the DR program? (Yes or No) |  |

If On-Site Generation is eligible, please describe any conditions for its participation (e.g. environmental constraints, operating hour limitations, permit requirements) |

<table>
<thead>
<tr>
<th>Operating Features and Requirements</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>NOTICE AND RESPONSE REQUIREMENTS: Please specify Advance Notice Provided or Demand Responsiveness Requirements. How long do customers have between notification of a program event and when they must reduce their demand? (hours)</td>
<td></td>
</tr>
<tr>
<td>NOTIFICATION: Please specify how operational information is conveyed to participants</td>
<td></td>
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<tr>
<td>DURATION: Please specify duration of the demand response when triggered</td>
<td></td>
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<tr>
<td>- Minimum Duration of Event (hours)</td>
<td></td>
</tr>
<tr>
<td>- Maximum Duration of Event (hours)</td>
<td></td>
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<tr>
<td>DISPATCHABILITY/FREQUENCY OF OPERATIONS: Please specify any limitations on overuse of DR programs, such as:</td>
<td></td>
</tr>
<tr>
<td>- Maximum number of events per year (or season)</td>
<td></td>
</tr>
<tr>
<td>- Maximum number of events per day</td>
<td></td>
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<tr>
<td>- Maximum cumulative duration (hours) per year</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>ONGOING TEST AND QUALIFICATIONS REQUIREMENTS</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>- Do you conduct periodic demand response tests? If yes, please describe frequency and procedures</td>
<td></td>
</tr>
<tr>
<td>PENALTIES: If participants do not comply with contracted demand reductions, are there penalties? If so, please describe.</td>
<td></td>
</tr>
</tbody>
</table>

| BUY-THROUGH OPTION: If participants cannot reduce demand, does the participant have opportunity to buy through a load curtailment event? (YES/NO) |  |
| - If participants can buy through, how much are they required to pay? |  |

| MONITORING & VERIFICATION (M&V) REQUIREMENTS: DR programs utilize a variety of M&V methods according to type of customers participating in the program, requirements for financial settlement, and requirements of the system dispatcher. Please specify which (one or more) of the following M&V approaches are used for each program: |  |
| - Interval metering of individual participating customers and application of a customer baseline (CBL) to calculate impacts |  |
| - Load impact estimates using load survey (load research) methods |  |
| - Estimates of aggregate load impacts using system-level or substation-level data |  |
| - Engineering estimates at the participant level based on connected load and demand response strategy |  |
| - Other: (Please specify) |  |

| CUSTOMER PERFORMANCE USING CUSTOMER BASELINE (CBL) CALCULATIONS: Comparing actual demand reductions with a baseline calculation is a common method of measuring customer performance. If you utilize customer base line to estimate actual load reductions, please specify your approach (see list of choices below; options are not mutually exclusive): |  |
| - Same day adjustments (uses data from event day before the curtailment period to align and shift the predicted usage to account for characteristics that may affect load on that day) |  |
| - Averaging methods (e.g., average of top 3 or 5 of 10 similar days within previous period) |  |
| - Regression methods |  |
| - Other (Specify) |  |

<table>
<thead>
<tr>
<th>Operating Benefits and Program Value</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>RESOURCE ADEQUACY BENEFITS: Can the DR load impacts be counted towards Planning Reserves Requirements? (YES/NO):</td>
<td></td>
</tr>
<tr>
<td>- Describe any requirements the program must meet to be included in Resource Adequacy planning</td>
<td></td>
</tr>
</tbody>
</table>
### Compensation for Participation

#### INCENTIVE DESIGN:
Describe the overall arrangements for compensating participants. 

#### COMPENSATION LEVEL:
Please indicate the amount of compensation provided on the appropriate row. If both capacity and energy payments are provided please indicate typical values for each.

- $/kW per year
- $/kWh
- $/appliance
- $/month
- Other (Please describe)

#### PERFORMANCE PAYMENTS:
If a pay-for-performance approach is used as a basic or supplemental compensation approach, please describe how it is calculated and provided ($/kWh).

#### COMPENSATION BASIS:
Describe the basis for determining the incentives or compensation payments.

### Program Participation and Potential

#### ELIGIBLE POPULATION:
Number of Eligible Customers/Sites in Target Population (as of May 2008)

#### PROGRAM ENROLLMENT:
Enrolled Customers/Sites (as of May 2008)

#### Peak Demand of Enrolled Customers/Sites (as of May 2008, in MW)

#### Potential (Contracted) Load Reduction Capability of Program Participants (as of May 2008, in MW)

#### MARKET POTENTIAL:
Has your utility ever done a study or estimated DR market potential? If yes, can you provide the study, or your estimate?

### Program Performance

#### PROGRAM RESULTS:
Was the program dispatched during 2007? (YES/NO) If yes, answer items below

- Number of Events or Event Days in 2007
- Average Demand Reduction due to the program during 2007
- On average, how frequently have DR program events been called in previous years (2004-2006)?
- How many times was the program dispatched due to system emergency conditions between 2004-2007?
- How many times was the program dispatched in response to high market prices between 2004-2007?

### Notes

- Demand Bidding/Buyback: A DR program where customers or curtailment service providers offer bids to curtail based on wholesale electricity market prices or an equivalent. Mainly offered to large customers (e.g., one MW and over), but small customer DR load can be aggregated by load serving entities or curtailment service providers and bid into the demand bidding program sponsor.

- OPERATIONAL TRIGGER (specify what can trigger program operations: list all below that apply)

  a) System emergency contingency: DR initiated in response to system emergency declared by SPP
  b) Market conditions: DR initiated in response to high wholesale electricity prices
  c) Contractual obligations: DR initiated to maintain aggregate demand below contracted levels
  d) Local Conditions: DR initiated to mitigate localized or utility specific reliability conditions or congestion constraints
  e) Other: (Please specify)

- ON-SITE GENERATION: On-site generation can include back-up power, emergency generators, or cogeneration. If only certain types of on-site generation are allowed please specify.

- NOTIFICATION: DR requests and notification can be communicated via one or more of the following channels. Please specify the communication channel(s) used in each program.

  a) Phone
  b) Internet
  c) Pager
  d) News media
  e) Automatic Control (e.g., equivalent to AGC) or automatic frequency response
  f) Direct to EMCS or control device
  g) Other: (Please Specify)

- COMPENSATION BASIS: Payments for customer participation can vary considerably. Please indicate what basis is used to calculate incentive payments for your DR program.

  a) avoided costs (marginal capacity costs)
  b) actual capacity costs (costs of a peaking unit)
  c) estimate of the value of load (value of unserved energy or value of lost load)
  d) Other
**Dynamic Pricing**

We define dynamic pricing to include Real Time Pricing (RTP) and Critical Peak Pricing (CPP) tariffs only. Do not include time-of-use tariffs in this category. Do not include Demand Response programs in this category. If there is more than one type of Dynamic Pricing tariff that is offered to various customer groups/classes, please fill out one column for each tariff.

### General Program Information

<table>
<thead>
<tr>
<th>Program 1</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Program Administrator</strong> (Cooperative, IPP, ITC, IOU, Marketeer, Municipal, State Agency)</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Tariff Name and Number</strong></th>
</tr>
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<table>
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<tr>
<th><strong>Tariff Applicability:</strong> Any seasonal applicability or is it in effect year round?</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Documentation:</strong> Has tariff been evaluated recently? (YES/NO) If so, when? Are results publicly available? If so please provide references.</th>
</tr>
</thead>
</table>

### Eligibility and Participation Requirements

<table>
<thead>
<tr>
<th><strong>Minimum Size Requirements:</strong> Specify any threshold conditions for participation</th>
</tr>
</thead>
</table>

- Customer peak demand (kW) or Consumption (kWh)
- Size of Load Reduction (kW)
- Voltage level
- Other (Please describe)

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<tr>
<th><strong>Customer Type:</strong> Specify any market segment eligibility requirements</th>
</tr>
</thead>
</table>

- Residential
- Commercial
- Industrial
- Other (Please describe)

<table>
<thead>
<tr>
<th><strong>Participation Requirements:</strong> Is the tariff Mandatory or Voluntary?</th>
</tr>
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</table>

<table>
<thead>
<tr>
<th><strong>Recruitment Approach:</strong> Is the tariff offered on an opt-in or opt-out basis?</th>
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</thead>
</table>

<table>
<thead>
<tr>
<th><strong>Program Exclusiveness:</strong> Can participants simultaneously participate in other DR, demand bidding, or dynamic pricing programs?</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>On-Site Generation:</strong> Can Onsite Generation be used in responding to dynamic price signals? (Yes or No).</th>
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</thead>
</table>

If On-Site Generation is eligible, please describe any conditions for its participation (e.g. environmental constraints, operating hour limitations, permit requirements).

### Operating Features and Requirements

<table>
<thead>
<tr>
<th><strong>Price Notification:</strong> Specify how variable pricing information is conveyed to participants</th>
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</table>

<table>
<thead>
<tr>
<th><strong>Dynamic Pricing Tariff Design:</strong> Characterize the type of dynamic pricing tariff</th>
</tr>
</thead>
</table>

- Do you utilize a one-part or two-part tariff? (Please Describe)
- What is the basis for the dynamic price? (Please Describe)

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<tr>
<th><strong>Load Impact Estimation:</strong> Utilities and ISOs utilize a variety of M&amp;V methods to estimate the load impacts of dynamic pricing tariffs, which may depend on the number and type of customers enrolled and program design features. Please specify the M&amp;V approach used for your dynamic pricing tariff(s), choosing from the indicative list below (select all options that apply).</th>
</tr>
</thead>
</table>

- a) Day Matching (load profiles for low-priced and high-priced days compared)
- b) Econometric approaches: Estimating price elasticity of demand or substitution elasticities by analyzing individual customer hourly usage and price data
- c) Baseline Load Profile Approaches (for CPP tariffs only, customer load profile compared for an "event day" vs. a "non-event day")
- d) Estimation of load impacts by comparing consumption for "treatment" and "control" groups
- e) Other: Specify

<table>
<thead>
<tr>
<th><strong>Access to Load Data:</strong> Do participants have access to hourly load data? If so, When? (Near-real time, daily, or NO access)</th>
</tr>
</thead>
</table>
### Operating Benefits and Program Value

**RESOURCE ADEQUACY BENEFITS:** Can the forecast load impacts of dynamic pricing tariffs be counted towards Planning Reserves Requirements? (YES/NO);

- Describe any requirements the program must meet to be included in Resource Adequacy planning

**RESOURCE SCHEDULING BENEFITS:** Does the utility factor in the expected load impacts of dynamic pricing when scheduling day-ahead requirements? If yes, please describe how.

**IMBALANCE ENERGY MARKET BENEFITS:** Are the expected load impacts of dynamic pricing included in calculating or meeting requirements of the energy imbalance service market? If so, please describe how.

### Program Participation and Potential:

**ELIGIBLE POPULATION:** Number of Eligible Customers/Sites in Target Population (as of May 2008)

**PROGRAM ENROLLMENT:** Enrolled Customers/Sites (as of May 2008)

Peak Demand of Enrolled Customers/Sites (as of May 2008) (in MW)

Potential (Contracted) Load Reduction Capability of Program Participants (MW as of May 2008) (in MW)

**MARKET POTENTIAL:** Has your utility ever done a study or estimated dynamic pricing market potential (YES/NO)? If yes, can you provide the study, or your estimate?

### Program Performance:

**PROGRAM RESULTS:** Was the program in place during 2007? (YES/NO) If yes, answer items below:

- What was the largest demand reduction achieved as a result of your dynamic pricing tariff?
- What were the corresponding price levels when this occurred?
- What strategies or enabling technologies did your customers utilize to respond to dynamic prices?*

### Notes

1. **RECRUITMENT APPROACH:** Opt-in means that customers are offered the chance to volunteer. Opt-out means all customers are placed on the tariff and must take positive steps (opt-out) to be removed from the tariff.

2. **ON-SITE GENERATION:** On-site generation can include back-up power, emergency generators, auto-production, or cogeneration. If only certain types of on-site generation are allowed please specify.

3. **PRICE NOTIFICATION:** Price signals may be sent using one or more of the following channels:
   - a) Phone
   - b) Internet
   - c) Pager
   - d) News media
   - e) Direct to EMCS or control device
   - f) Other: (Please Specify)

4. **TARIFF DESIGN:** A real-time pricing (RTP) tariff provides variable hourly pricing for all hours of the year. A critical peak pricing (CPP) tariff provides variable pricing only for a relatively few number of hours per year when the utility calls a CPP event.

5. **TARIFF DESIGN FEATURES:** A one-part dynamic pricing tariff assesses all volumetric (per kWh) charges based on variable hourly prices. A two-part dynamic pricing tariff incorporates a customer baseline (CBL) usage which establishes a long-term average hourly usage profile for each customer. Variable hourly prices are applied only to the differences between actual hourly load and the CBL. Two-part CBL-based real-time tariffs are a hedge against the implicit price-exposure risk of variable hourly prices as the bulk of a customer's consumption is billed on the customer's otherwise applicable tariff.

6. **TARIFF DESIGN:** (PRICING APPROACH) Variable prices are usually provided on an hourly basis. Hourly prices can be indexed to a day-ahead price forecast or forward market price schedule (e.g., day ahead market) or to a day-of cost or price schedule (real-time imbalance energy price schedule or system lambda). In some cases variable price indices can be indirectly estimated using a forecast proxy value, such as day-ahead hourly temperature or system demand.
### Southwest Power Pool Strategic Planning Committee

Customer Response Task Force

#### Retail Demand Response Program Survey

**Background:** Existing retail DR assets in the SPP footprint are not well characterized. The Customer Response Task Force of the SPP Strategic Planning Committee is conducting this survey in order to create a comprehensive inventory of retail DR programs and dynamic pricing tariffs in the region. Survey results will be used to characterize the DR resources available, inform SPP state regulatory commissions, and identify discontinuities in how DR is utilized in wholesale and retail markets in the region.

**Instructions for SPP Members and Utility DR Program Managers:**

1. Separate worksheets are provided for: (i) Retail Demand Response Programs; (ii) Dynamic Pricing tariffs; and (iii) Voluntary Demand Response Programs. Please be sure to fill out a separate worksheet for each category of programs. However, you can describe multiple programs within the same category on a single worksheet.

2. Please verify each data entry, provide any additional references if available (e.g., regulatory filings or annual program reports) and indicate "No Data" or "Not Applicable" where data is incomplete or inaccurate or the question is not applicable.

3. The survey effort is being conducted by the Energy and Environmental Technologies Division of the Lawrence Berkeley National Laboratory. If you have any questions please call or email Grayson Heffner [gcheffner@lbl.gov, (301) 330-0947] or Ranjit Bharvirkar [rrbharvirkar@lbl.gov, (510) 486-6544].

4. If you have already prepared descriptions and documentation for your demand response programs and dynamic pricing tariffs we are happy to work with this existing documentation. However, we might follow up where the existing documentation doesn't include specific information we're looking for.

5. We will be conducting a brief follow-up telephone interview for those SPP Members with significant DR programs and dynamic pricing tariffs. This follow-up telephone interview will help us: (i) clarify any questions about your response to this survey; and (ii) ask a few additional open-ended questions regarding your perspective on barriers to DR and dynamic pricing and prospects for future development of DR for retail and wholesale markets in the SPP Region. Please designate contact points for both this survey and the follow-up telephone interview using the "Contact Information" worksheet.

6. Please provide individual spread-sheets for operations in each state (i.e. if your company administers programs/tariffs in multiple states, please provide a response for each state separately).
**VOLUNTARY DEMAND RESPONSE**

We define voluntary demand response to include programs where customers voluntarily participate, making a "best efforts" attempt to curtail load during a system emergency, but do not receive any pecuniary compensation for their load reductions. Customers may receive non-pecuniary compensation in the form of "good will" or positive public relations, usually provided by the ISO/RTO or the load-serving entity or the local government.

<table>
<thead>
<tr>
<th>Program 1</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>General Program Information</strong></td>
</tr>
<tr>
<td>PROGRAM ADMINISTRATOR (Cooperative, IPP, ITC, IOU, Marketeer, Municipal, State Agency)</td>
</tr>
<tr>
<td>PROGRAM NAME</td>
</tr>
<tr>
<td>DOCUMENTATION: Has the program been evaluated recently? (YES/NO) If so, when? Are results publicly available? If so please provide references.</td>
</tr>
</tbody>
</table>

| Program Design and Results |
| RECURRENCEMENT: How does the utility recruit participants for its voluntary load reduction program? |
| CUSTOMER TYPE: Specify any market segment eligibility requirements (e.g. industrial, commercial, residential, other) |
| PARTICIPATION: How many participants/customers are enrolled in a Voluntary DR Program? |
| NOTIFICATION: Specify how system emergency information and instruction are communicated |
| PERFORMANCE: Has this program ever been called? If so, under what circumstances, when and how frequently and what level of MW reduction is achieved? |
| OUTREACH: Does the utility periodically contact enrolled customers to see if they are still willing to participate? |
| NON-PECUNIARY COMPENSATION: Does the utility offer any type of non-compensatory incentive (e.g. good corporate citizen recognition)? Please describe. |
Potential topics for the July 27/28 SPP Educational Forum on Demand Response ("DR")

Recall, these are either broadly stated or to be interpreted broadly as categories for topics.

Please score out your preferences numerically.
Your first choice should be given a "1", your second a "2", and so forth.
I left an area for comments, if you wish to add a specific thought or preference.

<table>
<thead>
<tr>
<th>Topic</th>
<th>Ranking</th>
</tr>
</thead>
<tbody>
<tr>
<td>State and/or federal regulator perspectives on DR</td>
<td></td>
</tr>
<tr>
<td>Customer perspectives on DR. All customers, but especially industrial customers</td>
<td></td>
</tr>
<tr>
<td>Retail/wholesale interface issues. How can retail programs participate in wholesale markets?</td>
<td></td>
</tr>
<tr>
<td>Smart grid, smart meter, and other technology solutions for DR</td>
<td></td>
</tr>
<tr>
<td>SPP specific regional demand response issues</td>
<td></td>
</tr>
<tr>
<td>Valuation methods for demand response participation</td>
<td></td>
</tr>
<tr>
<td>Education on the nexus between demand response and energy efficiency</td>
<td></td>
</tr>
<tr>
<td>“Top 10” criticisms of demand response and/or barriers to implementation.</td>
<td></td>
</tr>
</tbody>
</table>
Southwest Power Pool, Inc.

2008, 2\textsuperscript{ND} QUARTER

PROJECT TRACKING REPORT
History
The Southwest Power Pool Inc, Transmission Project Tracking program actively monitors the progress of approved SPP Transmission Expansion Plan (STEP) transmission projects. This effort is in response the SPP Board of Directors approved strategic plan which was approved January 30, 2007.

October 2006, SPP Strategic Plan

TRANSMISSION EXPANSION/ PROJECT TRACKING
SPP will put in place a program to actively monitor and support the progress of approved transmission expansion projects, emphasizing the necessity to initiate, seek regulatory approval, construct and operate approved projects. Additionally, SPP will endeavor to find ways to streamline the processes necessary for the development and completion of transmission upgrades.

The following steps should be taken:
1. SPP staff will develop a tracking and reporting tool for transmission expansion projects for quarterly reporting to the Board of Directors, Members Committee and Regional State Committee.
2. SPP Staff will be proactive in its support of the Membership in terms of Project approval, siting and cost recovery.
3. SPP Staff will report to the Board of Directors annually on its evaluation of the processes, planning, approval and construction of needed transmission, emphasizing areas of strength and weakness resulting in enhanced processes to streamline these efforts.

Assigned to: Transmission Working Group

Background
A quarterly project tracking cycle is conducted where SPP staff interacts with transmission owners to determine the progress of each approved transmission project. This 2008, 2nd quarter project tracking report charts the progress of all 2007 STEP projects approved by the Board of Directors in January 2008. SPP staff has issued Notifications To Construct (NTC) for those approved projects that are required for reliability. In this report, three key summaries of the projects are provided:

1) Transmission projects completed in 2006-2007
2) Status of transmission projects in the 4 year horizon, (through 2011)
3) Status of transmission projects in 10 year horizon, (through 2017)

Results
This 2008 2nd quarter project tracking report indicates the status of 715 projects with an estimated Engineering and Construction (E&C) value of $2.5 billion. The projects have been divided into the following three categories:

1. 2006 – 2007 Project Summary
2. 2008 – 2011 Project Summary
3. 2008 – 2017 Project Summary

2006 – 2007 Project Summary:
The 2006 - 2007 project summary denotes completion and commissioning of 135 projects with an E&C cost of $274 million.

![2006-2007 Project Summary Pie Chart]

Figure – 1) 2006 – 2007 Project Summary

2008 – 2011 Project Summary:
The 2008 – 2011 project summary denotes completion and commissioning of 366 projects with an E&C value of $1.2 billion.
2008 – 2017 Project Summary:

The 2008 – 2017 project summary denotes completion and commissioning of 573 projects with an E&C of $2.2 billion.
Summary Table

<table>
<thead>
<tr>
<th>Project Summary</th>
<th>Complete (#)</th>
<th>Mitigation Provided (#)</th>
<th>Delayed (#)</th>
<th>On schedule 4 Year (#)</th>
<th>On Schedule beyond 4 Year (#)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006 - 2007</td>
<td>$274 (135)</td>
<td>$8 (8)</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2008 - 2011</td>
<td>$7 (8)</td>
<td>$121 (76)</td>
<td>$160 (37)</td>
<td>$933 (246)</td>
<td>-</td>
</tr>
<tr>
<td>2008 - 2017</td>
<td>$7 (8)</td>
<td>$200 (93)</td>
<td>$160 (37)</td>
<td>$933 (246)</td>
<td>$884 (189)</td>
</tr>
</tbody>
</table>

All values in millions of USD.

Key Issues:
The project tracking program helps to identify certain key issues.

Example 1): Westar Energy and SPS have identified modeling errors which resulted in the identification of new projects. Once these modeling errors were corrected, the projects are no longer required.

Example 2): Transmission owners would like to conduct further study in order to investigate the need for a project. For instance KCPL would like to review the need for projects in their control area.

Example 3): Transmission owners investigating alternate projects to the proposed projects in the 2007 SPP Transmission Expansion plan list. For instance instead of installing 69 kV capacitors at Cashion and East Kingfisher install new interconnection with OGE or KAMO.

Notifications To Construct (NTC) Update:
Categorization of the NTC’s can be grouped in to three areas:

- Category, No Issue
  - 156 projects that were issued a NTC in January 2008 are proceeding and not being re-evaluated in the 2008 STEP.

- Category, Data Accuracy
  - There are some approved transmission projects which have been issued a NTC but the project owners have requested re-evaluation of the project. There are 87 project that have an issued NTC in 2008 that are being re-evaluated. There are various reasons for the re-evaluation. Rationale includes model error, investigation of alternate solutions and timing of the project due to impact of new generation or other new transmission projects.

- Category, Project Scope
  - For some transmission projects, the owner may have recommended change in scope and magnitude of the transmission upgrade. SPP is investigating the change and evaluating if the change requires TWG, MOPC and BOD approval or if
SPP can directly issue a revised NTC. For example, one NTC called for adding a 2\textsuperscript{nd} 161/69 kV transformer at Claremore. Due to space problem in the substation, the project owner, as alternative, recommends the upgrade of the transformer. While this is in line with the intent of the NTC but must assess if regional funding impacts are substantially different.

- Category, Data Error Correction
  - Additional evaluation has been requested for some transmission projects where data errors may have been identified or new information regarding the need for the transmission project has been provided. SPP may issue a revised NTC and update TWG, MOPC, BOD on these projects.

- Category, Alternative Mitigation Proposals
  - Some transmission projects are under evaluation to assess proposed alternative project solutions. For example, Clay Center to Greenleaf 115 kV is under consideration for being replaced by the alternative of Knob Hill – South Beatrice 115 kV. New load impacts needs to be considered in the evaluation.

**Conclusions:**
The SPP Transmission Project Tracking initiative helps projects owners maintain commitment and accountability in the face of regional reliability. The initiative spearheads communication between SPP and transmission owners which helps in resolving anticipated transmission issues before they become real reliability problems. Overall, SPP Transmission Project Tracking has an important role in maintaining reliability in the SPP footprint and with the SPP neighbors.