REGULAR MEETING
Monday, July 27, 2009
1:00 - 5:00 p.m.
Airport Marriott, Kansas City, MO

1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a Quorum
   b. Adoption of April 27, 2009 Minutes

3. UPDATES
   a. RSC Financial Report
   b. Other RSC Officer Reports
   c. FERC
   d. SPP

4. BUSINESS MEETING
   a. RSC 2008 Audit Report (action item) ....................................................... Les Dillahunty
   b. Synergistic Project Plan Report
      1. Overview ................................................................................................. Carl Monroe
      2. Integrated Transmission Plan (ITP) ........................................................ Bruce Rew
      3. Priority Projects ...................................................................................... Bruce Rew
      4. Cost Allocation ....................................................................................... Dr. Mike Proctor
         a. Balanced Portfolio Report
         b. Waivers
   c. Procedures to Site Interstate Transmission .............................................. Heather Starnes
   d. Communication and Next Steps .............................................................. Les Dillahunty
   e. Congestion Hedging Task Force Comments .......................................... Keith Sugg (AECC)
   f. Wind Integration Task Force Update ........................................................ Bruce Rew
   g. Discussion of 6/24/09 FERC Technical Conference – Entergy ICT ....Chairman Paul Suskie
      Chairman Barry Smitherman
   h. Eastern Interconnection Planning Collaborative (EIPC) Comments .......... Bruce Rew
      Chairman Paul Suskie
   i. States Comments on Order 719 Tariff Language concerning Demand Response and Aggregators of Retail Customers Certification of Declaration Requirement .................... RSC Commissioners
   j. RSC Consulting Contract ........................................................................ Chairman Paul Suskie

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

*The Project Tracking Report will be included in the background material.
Southwest Power Pool
REGIONAL STATE COMMITTEE
Skirvin Hotel, Oklahoma City, OK
April 27, 2009

• M I N U T E S •

Administrative Items:
The following members were in attendance, via teleconference, or represented by proxy:
Stacy Starr-Garcia, for David King New Mexico Public Regulation Commission (NMPRC)
Mike Moffet, Kansas Corporation Commission (KCC)
Jeff Cloud, Oklahoma Corporation Commission (OCC)
Jeff Davis, Missouri Public Service Commission (MoPSC)
Mike Siedschlag, Nebraska Power Review Board (NPRB)
Barry Smitherman, Public Utility Commission of Texas (PUCT)
Paul Suskie, Arkansas Public Service Commission (APSC)

Vice President Mike Moffet called the meeting to order at 1:05 p.m. He asked for a round of introductions and a quorum was declared. There were 103 in attendance either in person or via phone (Attendance & Proxies – Attachment 1). Tim Texel and Mike Siedschlag were recognized and welcomed from the Nebraska Power Review Board.

Vice President Moffet asked for adoption of the January 26, 2009 meeting minutes (RSC Minutes 1/26/09 - Attachment 2). Paul Suskie moved to approve the minutes and Jeff Davis seconded the motion. The minutes were approved unanimously.

Updates
RSC Financial Report
Les Dillahunty provided the RSC Financial Report (Financial Report – Attachment 3). Mr. Dillahunty reported that the RSC remains under budget. There was no technical conference held although there are expected cost expenditures for cost/benefit studies.

Other RSC Officer Reports
There were no other officer reports.

FERC Update
Mr. Patrick Clarey provided an update on FERC activities. In February, the Commission approved two innovative rate treatments for transmission projects designed to bring wind generated electricity to the Southwest. On March 19, 2009, President Obama appointed Jon Wellinghoff as permanent FERC Chair and announced his intention to reappoint Commissioner Suedeen Kelly to another term. Other March activities included:

- Granted a one-time extension to SPP’s waiver request to allow SPP to study pending generator interconnection requests in two transitional clusters pending filing of queue reform filing.

- Accepted SPP’s tariff revisions adopting Order No. 890’s five-year minimum contract term and one-year notice period related to a firm transmission customer’s ongoing right to renew or rollover its contract. Additionally, the Commission instituted a Section 206 proceeding to determine the justness and reasonableness of certain language in SPP’s existing OATT regarding rollover provisions.
Regional State Committee
April 27, 2009

- Approved rate incentives for two ITC Great Plains high-voltage lines in SPP. The lines are part of the KETA and Kansas V Plan projects.
- Issued a proposed policy statement and action plan to provide guidance to inform the development of a smarter grid for the nation’s electric transmission system.
- Held a technical conference exploring challenges posed by the integration of large amounts of variable renewable generation into wholesale markets and grids as well as innovative solutions.

At the April open meeting, Chairman Wellinghoff announced the following staff changes:

- Shelton Cannon, current Office Director of the Office of Energy Market Regulation (OEMR), will retire after 29 years.
- Mike McLaughlin will be the new Office Director of OEMR.
- Jamie Simler will be the new Office Director of the newly created Office of Energy Policy and Innovation.

The Commission also approved rate incentives from the Green Power Express transmission project. The project is a proposed 3,000 mile regional high voltage project designed to deliver renewable energy from the upper Midwest to central and eastern load centers.

Senior staff continues their participation in ongoing outreach to the state commissions covered under classic SPP RTO as well as the SPP ICT arrangement with Entergy and the SPP ITO arrangement with E.ON. On June 24 in connection with the SEARUC Annual Meeting in Charleston, South Carolina, FERC and the Entergy states will hold a joint conference to explore issues with the ICT arrangement.

SPP Update
Les Dillahunty provided an SPP update in the absence of Nick Brown, who was detained at a Washington, D.C. meeting. Mr. Dillahunty extended SPP’s gratitude for the leadership and efforts of the CAWG over the last two years in the development of the Balanced Portfolio. He recognized Larry Holloway, an original member of the CAWG who has retired from the Kansas Corporation Commission, and called attention to his insightful leadership with this group.

Mr. Dillahunty stated that release of the Joint Coordinated System Plan (JCSP) in February may have caused some confusion. There are two initiatives underway: 1) the Eastern Wind Integration Task Force (EWITS), an earlier work of the JCSP is being expanded and carried forward; and 2) the Eastern Interconnection Planning Collaborative (EIPC) which is an effort to provide an integrated, interconnection-wide view of the regional plans and to provide an analysis identifying gaps relative to state, provincial, regional or federal policy goals. It is hoped that the EIPC will move toward an assessment and coordination of a variety of transmission alternatives. Seventeen Planning Authorities from the U.S. and Canada met April 8 to begin these EIPC discussions.

Mr. Dillahunty reminded the group that the SPP Board of Directors will hold the annual educational meeting in Little Rock on June 8 and 9. There is no corresponding RSC meeting in June although the SPP Board of Directors meeting is an open meeting. Please let one of the SPP staff know if you plan on attending and would like more information.

Business Meeting
RSC Bylaws Revision
Due to the recent integration of the Nebraska entities, the Nebraska Power Review Board (NPRB) now wishes to be included in the RSC. The RSC Bylaws do need to undergo a slight modification to accommodate the NPRB participation (Bylaws Revision – Attachment 4). It was recommended that this minor modification be made to include the NPRB. Mike Siedschlag, NPRB Chairman, was asked to comment. Mr. Siedschlag
Regional State Committee  
April 27, 2009

stated that the NPRB included five people appointed by the governor and three staff including Tim Texel, General Counsel. Jeff Davis moved to approve the RSC Bylaws modifications to Article II, 1a:

Regulate the retail electricity or distribution rates or approve retail service areas of transmission-owning members or transmission-dependent utility members of the SPP

Paul Suskie seconded the motion, which passed unanimously.

Jeff Cloud moved to include NPRB as a member of RSC. Paul Suskie seconded the motion, which passed unanimously. Mike Siedschlag will represent NPRB on the RSC.

Order 719 Tariff Language – Demand Response Participation in Markets

Les Dillahunty stated that Jim Eckelberger, SPP Board Chairman, had requested that the RSC agenda include discussion regarding the Order 719 tariff language (Order 719 Tariff Language – Attachment 5). The Markets and Operations Policy Committee (MOPC) proposed tariff revisions are:

MOPC proposed revision to RTWG approved tariff language to require certification, by means of a declaration by the relevant electric retail regulatory authority that a DRR or ARC, when registering to participate in the EIS Market, is not precluded by the laws and regulations of the relevant electric retail regulatory authority.

It was pointed out that FERC allows participation in the DRR and ARC markets if not precluded by state law. Following discussion, Barry Smitherman recommended that the RSC members take this back to each state commission and present comments and answers as to how the “declaration” could be addressed under each state’s laws. These findings will be reported at the RSC’s July meeting. SPP was instructed to send a letter to the RSC with the proposed wording of the Tariff language.

Future Markets Cost/Benefit Study Report

Roy True (ACES Power Marketing) stated that the MOPC endorsed the “SPP Cost Benefit Study for Future Market” report April 15 and asked that the RSC endorse this study and the recommendation to move forward. Mike Moffet moved to endorse the MOPC’s recommendations regarding SPP’s Future Markets. Jeff Davis seconded the motion, which passed unanimously. Barry Smitherman requested that the RSC receive frequent updates moving forward.

Cost Allocation Working Group (CAWG) Report

Dr. Mike Proctor presented the CAWG report (CAWG Presentation – Attachment 7). Dr. Proctor provided an update on:

- 2008 Unintended Consequences: Dr. Proctor provided a summary of the Base Plan projects and stated that the methodology for Unintended Consequences appears to be doing what was intended. The RSC concurred with the CAWG’s endorsement of the Unintended Consequences review.

- CAWG – 2009 Work Plan: Dr. Proctor reported that the Work Plan is being revised and will be ready
for the July meeting.

- Balanced Portfolio: For the Balanced Portfolio Summit, the SPP staff did a full analysis of Portfolio 3. Based on the analysis, it was determined that Portfolio 3-D was superior. Further analysis of the upgrades in Portfolio 3-D resulted in Portfolio 3-E, which found it of more benefit to remove Chesapeake and Reno-Summit from the portfolio. Dr. Proctor recommended that the RSC approve the Balanced Portfolio 3-E “Adjusted” as unanimously approved by the MOPC on April 15. Paul Suskie moved to approve the recommended portfolio. Barry Smitherman seconded the motion, which passed unanimously. SPP staff is to complete the final report.

- EHV Cost Allocation: The CAWG reached these findings:
  - If the future use of the EHV system is proportional to each Transmission Customer’s load ratio share, then the crediting mechanism for a two-part rate is relatively simple to implement.
  - If future use of the EHV system is not proportional to each Transmission Customer’s load ratio share, then the crediting mechanism for a two-part rate becomes more complex.

  The CAWG will be working on a final recommendation regarding a simple or more complex two-part rate.

Synergistic Project Planning Team Report
Carl Monroe provided an update on progress of the Synergistic Project Planning Team (SPPT) (SPPT Report – Attachment 8). Mr. Monroe stated that SPP Senior Staff recommended the formation of the Synergistic Planning Project Team (SPPT) to address comprehensive transmission planning and allocation of transmission costs without being encumbered by any limitations. He then introduced the team:

- Paul Suskie, Chairman, Arkansas Public Service Commission
- Barry Smitherman, Chairman, Public Utility Commission of Texas
- Kelly Harrison, Vice President – Transmission Operations and Environmental, Westar Energy
- Ricky Bittle, Vice President - Planning, Rates and Dispatching, Arkansas Electric Cooperative Corp
- Rob Janssen, President and General Manager, Dogwood Energy
- Ric Abel, Managing Director, Prudential Capital Group
- Carl Monroe, Executive Vice President and COO, SPP
- Mark Rossi, Accenture, Facilitation and Administration

The group developed five Planning Principles and made the following recommendation:

SPP should implement an Integrated Planning Process (IPP) to facilitate the creation of a robust, flexible, and cost-effective transmission network for the SPP footprint.
- Replace the Reliability Assessment, the Balanced Portfolio, and the EHV studies with an Integrated Planning Process
- More proactive in transmission expansion and commitments to a more forward looking transmission system
- Generation Interconnection and Aggregate Study Process studies would be less burdensome
- Would also reduce the cost allocation methods

The BOD should develop a plan to monitor the approved IPP facilities to ensure construction.
- SPP Staff will submit a preferred long range transmission plan and the associated cost benefit results to the BOD for approval after input from stakeholders and the RSC.
- Once approved, the BOD develop the appropriate monitoring plans to ensure the long-term commitment to these approved plans Subject to the cost allocation methodology developed.
Jeff Davis moved that RSC endorse the principles and concepts as set forth in SPPT report and endorse the recommendations. Barry Smitherman seconded the motion, which passed unanimously.

The IPP scope will include:

- Focus on regional needs not local needs
- Connect known load centers to known or expected large generation sources with a transmission backbone
- 20 year time horizon – 40 year benefits/costs analysis
- Strengthen existing ties to Eastern Interconnection and strong enough to provide the option of connecting to Western grid
- Updated every three years and in service dates/projects reviewed/modified; possible review for reliability every year
- Results from this process - list and need date of transmission expansion projects represents the long range plan for transmission expansion in the SPP region

SPP, in collaboration with the RSC, will engage a consultant to perform a detailed cost/benefit analysis of the proposed long-range transmission plan. This analysis will become part of each IPP three-year cycle.

Vice President Moffet commended the group on its excellent work. Barry Smitherman complimented Carl Monroe, the SPP staff and the stakeholders involved for their work and commitment.

**Scheduling of Next Regular Meeting, Special Meetings or Events:**

Vice President Moffet noted that the next regularly scheduled meeting is on July 27, 2009 in Kansas City, MO.

With no further business, the meeting was adjourned at 5:50 p.m.

Respectfully Submitted,

Les Dillahunty
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Net Income (Loss)  
- - - -
SOUTHWEST POWER POOL REGIONAL STATE COMMITTEE

FINANCIAL STATEMENT

FOR THE YEAR ENDED DECEMBER 31, 2008

with

REPORT OF INDEPENDENT AUDITOR
Report of Independent Auditor

Board of Directors
Southwest Power Pool Regional State Committee

We have audited the accompanying statement of cash receipts and disbursements of Southwest Power Pool Regional State Committee, (a non-profit organization, public-benefit corporation) for the year ended December 31, 2008. This financial statement is the responsibility of the Organization’s management. Our responsibility is to express an opinion on this financial statement based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statement of cash receipts and disbursements is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the statement of cash receipts and disbursements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the statement of cash receipts and disbursements. We believe that our audit provides a reasonable basis for our opinion.

As described in Note 1, this financial statement has been prepared on the cash receipts and disbursements basis of accounting, which is a comprehensive basis of accounting other than generally accepted accounting principles.

In our opinion, the statement of cash receipts and disbursements referred to above presents fairly, in all material respects, the cash receipts and disbursements of Southwest Power Pool Regional State Committee, for the year ended December 31, 2008, on the basis of accounting described in Note 1.

Patricia Salman & Associates, PLLC
May 11, 2009

Patricia Salman & Associates, PLLC

MEMBER:
American Institute of Certified Public Accountants
Arkansas Society of Certified Public Accountants
SOUTHWEST POWER POOL REGIONAL STATE COMMITTEE

STATEMENT OF CASH RECEIPTS AND DISBURSEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

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See accompanying notes and accountant’s report
Note 1: Significant Accounting Policies

Nature of Operations

The primary purpose of SOUTHWEST POWER POOL REGIONAL STATE COMMITTEE (the Organization) is to provide collective state regulatory agency input to Southwest Power Pool, Inc. on matters of regional importance related to the development and operation of bulk electric transmission. The Southwest Power Pool Regional State Committee is comprised of retail regulatory commissioners from agencies in Arkansas, Kansas, Missouri, New Mexico, Oklahoma and Texas.

The Organization is incorporated in the State of Arkansas as a public-benefit corporation.

Basis of Presentation

The accompanying financial statement has been prepared on the cash receipts and disbursements basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. As a result, certain revenue and the related assets are recognized when received rather than when earned and certain expenses are recognized when paid rather than when the obligation is incurred.

Income Taxes

The Organization is exempt from income taxes under Section 501(c)(4) of the U.S. Internal Revenue Code, except for taxes pertaining to unrelated business income. No provision for income taxes was required for the period ended December 31, 2008.

Note 2: Related-party transactions

The Organization provides regulatory input to Southwest Power Pool, Inc., which in turn provides administrative financial funding for the Organization. Funding for this reporting period was approximately $819,000.
Motion to Adopt 2008 Financial Statements and Audit Report.

I move that the RSC Board of Directors accept the 2008 Financial Statements of Southwest Power Pool Regional State Committee and the related Report of the Independent Auditor which were both submitted, on May 11, 2009, by Patricia Salman & Associates, PLLC.
Helping our members work together to keep the lights on... today & in the future

Integrated Transmission Plan (ITP)
What is Integrated Transmission Planning?

- **ITP:** New effort to develop proactive regional transmission planning principles
- **Goal:** Build robust grid to meet near- and long-term needs
- **Horizon:** 5, 10, and 20 year
- **Focus:** Regional, integrated with local
- **Update:** Every three years
- **Resulting in:** Comprehensive list of needed projects for SPP region over next 20 years

What is Integrated Transmission Planning?

- **Major Objective:** Design transmission backbone to connect load centers to low-cost generation
- **Other Objectives:**
  - Integrate SPP’s east and west regions
  - Make transmission an enabler rather than constraint
  - Strengthen ties to Eastern and Western Interconnections
How ITP is being developed?

- Staff is working with Stakeholders on the ITP process
  - Conducting conference calls to gather Stakeholder input
  - Revising the ITP process based on Stakeholder comments/suggestions

Status of ITP

- A detailed schedule developed to meet aggressive timeline
- Third draft of ITP process submitted to stakeholders for comment
- Study scope document under development by staff
Next Steps

- Meeting every other week
- Next Face to Face meeting August 20, 2009 in Kansas City
- Distribute final ITP process September 24, 2009
What are Priority Projects?

- Congestion Corridors
- Transmission Service Requests
- GI Corridors
- Economic Projects
- West – East Transfer Capability
Priority Project Screening

- Approximately 120 Priority Projects initially
- Screening criteria netted down to 20
- Presented at MOPC and netted down from 20 to 10

Priority Projects Screened List

- Hitchland – Woodward (765kV)
- Spearville – Comanche - Medicine Lodge – Wichita (765kV)
- Comanche/Medicine Lodge – Woodward (765kV)
- Woodward – Elk City – LES - Seminole (765 kV)
- Wichita – Wolf Creek (765 kV)
- Stateline - Potter - Roosevelt – Tuco 345kV
- Valliant – NW Texarkana (345 kV)
- Woodward – Woodring (345 kV)
- Cooper South constraint 345 kV solution
- Riverside Station – Tulsa Power Station (Rebuild) 138kV
765 kV Projects

• 765 kV projects will be modeled
• 765 kV projects will also be evaluated as a 765 kV running at 345 kV
How is the Priority Project list finalized?

- Extensive analysis is performed on these projects
- Projects with a Benefit to Cost analysis that is > 1 will be recommended
Conclusion

- A systematic approach to prioritizing projects
- Includes Stakeholder involvement and review
- Submission to the BOD the finalized list of Priority Projects for approval
- Work with Stakeholders to help facilitate implementation of these projects
Bruce Rew
Vice President, Engineering
501-614-3214
questions@spp.org
Highway/Byway
Cost Allocation
and Rate Design

RSC Meeting
Mike Proctor
Kansas City, MO
July 27

Outline

A. Highway/Byway Concepts
B. Highway/Byway Cost Allocation
C. Highway/Byway Rate Design
D. Integrating Cost Allocation and Rate Design
E. Upcoming CAWG Schedule
A. Highway/Byway Concept

- Highway/Byway is a conceptual framework by which certain transmission facilities are classified:
  
  **Highway** = Regional Transmission Facilities whose primary function is to transmit power from distant generation to load.
  
  **Byway** = Local Facilities that provide Generators and Loads access to one another and access for both to the Highway.

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Pictorial Representation of Highway/Byway

- Different size boxes for G and L indicate differences in MWs or MWhs within the various zones.
- Straight arrow direction denotes flow into the zone when L>G and into the highway when G>L.
- Curved arrows indicate loop flows onto the Highway from G serving L in each zone.
- Imports and Exports are connected to the highway.
B. Cost Allocation

Cost Allocation requires a contextual framework.

1. The reasons behind the transmission upgrades – The drivers that are being assumed for the need of the upgrades.
2. The benefits resulting from the transmission upgrades – A demonstration that the upgrades are cost-beneficial.

Past Contextual Frameworks

Reliability Upgrades
1. Need – maintain reliable transmission grid
2. Benefits – “keep the lights on”

Transmission Service Upgrades
1. Need – reliable delivery of power from resources to load
2. Benefits – demands for power by load are met

Economic Upgrades
1. Need – reduce congestion on the transmission system
2. Benefits – adjusted production cost savings

Generation Interconnection Upgrades
1. Need – access for generator to the transmission system
2. Benefits – generator is able to sell power in RTO market and load may be able to purchase at lower prices.
Contextual Framework for Highway/Byway Rate Design

CHANGES:
• Previously, generation designated as resources for loads were located within or close too the zones of the loads being served.
• With the need for renewable energy sources, the best generation locations are no longer in the zones of the loads being served.

NEED: A transmission highway to which the best generation sources can connect and which will deliver the power from those resources throughout the SPP footprint.

BENEFIT: From a transmission highway
1. Generation located in the best wind regions of SPP will benefit from having access to loads throughout the SPP.
2. Load within the wind regions will benefit from not having the power from the wind generation being trapped within their zones.
3. Load outside the wind regions will benefit from having ready access to renewable energy sources.

C. Rate Design Objectives

A. Balance Cost Allocation Among
   – Beneficiaries and Cost Causers
     • Some beneficiaries may not be direct cost causers
   – Cost Causers and Free Riders/Late Comers
     • Cost causers related to accesses and uses that determine why facilities are built, but other access and uses may subsequently benefit from same facilities
   – Transmission Access and Transmission Use
     • Some benefit from just having access to the highway and others get additional benefits from greater use of highway facilities

B. Differentiate Regional vs. Local Facilities
   – New EHV (345 kV and above) likely to be primarily regional (highway) facilities
   – Lower voltage likely to be primarily local (byway) facilities

C. Simplify Accounting Processes
   – Challenge is to achieve balance without making the rate design too complex
Proposals Thus Far
(50,000 ft View)

May CAWG Meeting
- Westar/OGE & SPP Staff
  - Division of Facilities between Highway/Byway
  - Load Pays Highway Rate
- Two-Part Highway Rate
  - Load funds the highway construction
  - New Generation pays for access to/use of the highway

June CAWG Meeting
- Byway Rate using Existing Cost Allocations
- Generation Pays Highway Rate

July CAWG Meeting
- Injection-Withdrawal / Access-Usage Rate
  - From MISO presentation at July 8 OMS meeting.
- Possibly other Byway Proposals
  - Example: 100% Byway goes to zonal rates.

D. Integrating Cost Allocation With Rate Design

Primary Question: What upgrades should be included in the Highway/Byway rate design?

1. All upgrades required to meet the objectives of delivery of power from wind resources\(^1\) throughout the SPP footprint.
   - Appears to have agreement among the states – can we have a brief discussion to confirm?

2. Other upgrades that don’t contribute to delivery of power from wind resources, but are needed for reasons associated with the contextual framework from the past.
   - Needs further discussion among the states at CAWG?

\(^1\)Note: Delivery of power from wind resources is being used as the primary context, but there may be other drivers for the Highway such as carbon policy, smart grid, price sensitive demand, distributed generation, electric cars, etc.
Reliability Upgrades

- Once the Highway (ITP 20 year) is in place, are most of the Reliability upgrades (ITP 10 year) Byway in nature?
  - Will 10 year upgrades include 345 upgrades that are not a part of the Highway (20 year)? Probably not, but we will need to decide what to do if this occurs.
- If most, but perhaps not all, of the ITP 10 year upgrades are lower voltage, is the existing allocation for reliability upgrades (1/3 PS & 2/3 Zonal) still appropriate?
  - Should lower voltage upgrades still receive a 1/3 postage stamp allocation, or should these be 100% zonal (strictly Byway)?
  - Should higher voltage upgrades receive a 100% postage stamp allocation (strictly Highway)?
Aggregate Study Upgrades

- Once the Highway is in place, are most of the Aggregate Study upgrades Byway in nature?
  - Will Aggregate Study upgrades include 345 upgrades that are not a part of the Highway?
- If most, but perhaps not all, of the Aggregate Study upgrades are lower voltage, is the existing allocation of reliability upgrades (1/3 PS & 2/3 Zonal) still appropriate?
  - Should lower voltage upgrades still receive a 1/3 postage stamp allocation, or should these be 100% zonal?
  - Should higher voltage upgrades receive a 100% postage stamp allocation?

Economic Upgrades

- Certain economic upgrades are associated with the improved deliverability of wind to the SPP footprint.
  - Even with basic deliverability upgrades, congestion (higher LMPs at load destinations vs. lower LMPs at wind sources) may exist that can be fixed on a cost-beneficial basis.
    - These kinds of EHV economic upgrades should be included in ITP 20 year plan. This will take significant discussion at ESWG.
  - Other economic upgrades may be associated with other forms of congestion.
    - Not clear how these will be evaluated in ITP 20 year plan.
    - Adjusted Production Costs can be applied as one of the benefit metrics, but need the Highway (ITP 20 year plan) as a backdrop to properly determine these benefits.
Generation Interconnections

• The Highway will provide the EHV backbone to which generators can connect.
• There will be additional Byway facilities needed to collect wind generation for connecting to the Highway.
  – Are the costs of these collector systems to be 100% allocated to generators?
  – What if some of these collector systems are 345 kV, but are devoted to generation access?

Cost Allocation and Rate Design for Priority Projects

• Final determination of priority projects is in process.
• However, all EHV projects currently being evaluated appear to fit into the “deliverability” category.
  – 765 kV Overlay Projects that connect to Balanced Portfolio Projects, add Highway Facilities for Wind GI, and add West to East Deliverability to SPP footprint:
    √ Spearville – Comanche/Medicine Lodge – Wichita (765kV)
    √ Comanche/Medicine Lodge – Woodward (765kV)
    √ Woodward – Elk City – LES - Seminole (765 kV)
    √ Wichita – Wolf Creek (765 kV) – Primarily Adds W→E Deliverability
    √ Hitchland – Woodward (765kV) – Primarily Adds Wind GI
  – 345 kV Projects that relieve trapped generation and add Deliverability to SPP footprint
    √ Stateline - Potter - Roosevelt – Tuco 345kV – Relieve Trapped Wind Gen
    √ Woodward – Woodring (345 kV) – Added Deliverability
    √ Valliant – NW Texarkana (345 kV) – Added Southeast Deliverability
    √ Cooper South constraint 345 kV solution – Added Northeast Deliverability
• Biggest task will be ranking these projects to determine which ones to include in projects to be implemented prior to ITP
Cost Allocation and Rate Design for Existing Facilities

• SPP Staff providing rate impacts from moving existing 345 kV facilities to a region-wide postage stamp rate.

• Because of aggressive schedule for new facilities, issue on existing facilities put on back burner.
  – SPP Staff provides brief update on rate impact estimates at meetings.

E. Upcoming CAWG Schedule

• August – Two Meetings with focus on Highway Cost Allocation and Rate Design
• September – Two Meetings with focus on Byway Cost Allocation and Rate Design
• October – One Early Meeting (prior to RSC Meeting) to finalize concepts for Highway/Byway Cost Allocation and Rate Design.
I. Introduction

The siting of transmission facilities within the SPP region is generally a matter that lies within the jurisdiction and authority of the states and their regulatory commissions. While certain limited “backstop” transmission siting authority was granted to the Federal Energy Regulatory Commission (“FERC”) by the Energy Policy Act of 2005, it only applies where the Secretary of the Department of Energy (“Secretary” or “Department of Energy”) has designated a “national interest electric transmission corridor.” No area within the SPP footprint currently has such a designation.

While SPP, through the STEP process, has the authority to direct transmission owners to construct facilities necessary to provide transmission service to customers, ensure reliability of the transmission system, or take advantage of economic opportunities, the states, through their certification and siting processes, play a critical role in determining where and how transmission expansion will occur. State certification and siting laws continue to have full force and effect. Moreover, SPP’s transmission planning process, outlined in Attachment O of the SPP Tariff, envisions participation by state regulatory commissions throughout the planning process.

To understand the role of state and federal siting laws in this process, this paper first provides a broad overview of the transmission siting process at the state level, then discusses FERC’s currently limited “backstop” siting authority under EPAct 2005, and concludes with a discussion of legislation currently under active consideration by the U.S. Congress that may modify federal transmission planning and siting authorities and thus impact the SPP planning process.

II. Summary of Conclusions

In reviewing state and federal transmission siting requirements, SPP reviewed the following issues, concerns, and policies:

**Question:** What is the role of state siting in the SPP planning process?

**SPP Conclusion:** States retain primary authority for approving the siting of transmission facilities, even following the passage of EPAct 2005. Because state siting is critical to bringing SPP transmission planning and construction plans to fruition, coordination with state regulatory authorities will continue to be a significant aspect of SPP’s transmission planning efforts.

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2. There is significant Congressional activity underway regarding energy legislation as this paper is being written. The discussion of pending legislation is accurate as of July 17, 2009.
Question: What is the role of federal siting in the SPP planning process?

SPP Conclusion: Currently, federal transmission siting authority does not impact SPP because no area within the SPP region has been designated a “national interest electric transmission corridor” by the Secretary of the Department of Energy. To the extent that the Secretary designates an area within the SPP region to be a national interest corridor, federal transmission siting authority could only arise where a state fails to act on an application for the siting of a transmission project within one year of submission of the application (except possibly in Oklahoma or Louisiana where the relevant state utility commissions currently do not exert authority over transmission siting).

Question: What are the procedures for federal “backstop” transmission siting authority?

SPP Conclusion: Federal “backstop” transmission siting authority arises in designated “national interest electric transmission corridors” only if a state that has authority to act on an application for the siting of a transmission facility has failed to act on the application within one year after its submission. In considering an application, FERC considers any findings of state regulators, coordinates environmental reviews with the affected state(s), and permits state regulator involvement throughout the pre-filing and application processes. FERC also coordinates system analyses with Regional Transmission Organizations (“RTO”) and Independent System Operators (“ISO”) and affords “due weight” to the findings and conclusions of RTOs and ISOs.

Question: How might pending federal legislation impact transmission siting in SPP?

SPP Conclusion: Current legislation pending before the U.S. Congress modifies the transmission siting authority granted to FERC by EPAct 2005. The U.S. Senate is considering legislation that would extend FERC siting authority throughout the United States when a state fails to act or denies an application. This siting authority no longer would be limited to national interest electric transmission corridors, although it would apply only to Extra High-Voltage (“EHV”) facilities (defined as facilities operating at or 345-kV for alternating current or at or above 300-kV for direct current). The Senate legislation also would expressly allow FERC to allocate costs of EHV facilities broadly across a region, but only to customers who derive “measurable economic and reliability benefits” from a transmission project. The U.S. House of Representatives has also passed legislation that would provide
FERC with siting authority, but only in the Western Interconnection, if a state fails to act or denies a siting application. It is difficult to predict the outcome of these legislative efforts at this time.

III. State Siting Laws and Procedures in the SPP Region

The SPP Membership Agreement and Open Access Transmission Tariff (“OATT” or “SPP Tariff”) explicitly recognize the role of the states in transmission siting. Under the Membership Agreement, Transmission Owners are required to:

use due diligence to construct transmission facilities as directed by SPP in accordance with the OATT and this Agreement, subject to such siting, permitting, and environmental constraints as may be imposed by state, local and federal laws and regulations, and subject to the receipt of any necessary federal or state regulatory approvals, including, as necessary, the Member’s governing board where it serves as that authority.

Thus, state siting proceedings are a critical part of bringing the results of the SPP planning process to fruition. Nothing in the SPP Membership Agreement or Tariff preempts the applicability of state siting laws. To the contrary, the governing SPP documents explicitly recognize the states’ roles.

Generally, but with the notable exceptions of Oklahoma and Louisiana, entities planning to construct new transmission facilities in the SPP region must apply for and obtain a certificate of public convenience and necessity in the state(s) where the facility will be located. While each state has distinct application requirements and unique criteria for granting a certificate of convenience and necessity, some common attributes exist. Most states require an applicant to submit information regarding the proposed route or location of the transmission facility, and many require information regarding the cost of construction, economic and environmental impacts, impact on other utility services, and impact on landowners. Two states (Arkansas and Kansas) also provide for assessment of the impact and benefits to other states from the proposed transmission project (for Arkansas, this arises specifically in the context of a project proposed in a national interest electric transmission corridor, as discussed in more detail in the attached Appendix). State laws vary regarding whether and to what extent an extension or upgrade to an existing facility requires a new certificate of convenience and necessity.

Hearing requirements also vary, but most states will conduct an evidentiary hearing prior to issuing a certificate of convenience and necessity for a proposed transmission project, although some state commissions are permitted to waive hearing requirements in certain circumstances. It also is the custom in certain states, such as Kansas and Oklahoma, to hold community meetings along the proposed route of a transmission line prior to official hearings regarding proposed transmission projects.

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3 Southwest Power Pool, Inc., Membership Agreement, Original Volume No. 3 § 3.3(a) (emphasis added).
4 It also is the custom in certain states, such as Kansas and Oklahoma, to hold community meetings along the proposed route of a transmission line prior to official hearings regarding proposed transmission projects.
application to the issuance of an order, up to one year or longer. State utility commissions in most of the states in the SPP region are required to act on an application for a certificate of convenience and necessity within one year, which, as discussed below, is critical to determining whether FERC “backstop” siting authority may be triggered. FERC may only act on a siting application under its “backstop” authority if a state commission has failed to act within one year from the time the application was submitted to the state commission.

The SPP planning process and each state’s exercise of its jurisdiction over siting work side by side, as both are crucial to the development of the necessary regional transmission system. State proceedings may occur at any time in the process, at the discretion of state regulatory authorities, but often will follow SPP’s determination of the need for a particular new facility.

A more detailed state-by-state summary of transmission siting approval procedures is attached as Appendix 1.

IV. Existing Federal Transmission Siting Laws and Regulations

EPAct 2005, enacted on August 8, 2005, grants authority to FERC to approve the siting and construction of electric transmission facilities located in “national electric transmission corridors,” as established by the U.S. Department of Energy, if states “withhold approval” of a project for longer than one year or are not authorized to consider the project or certain aspects of the project. States can avoid the exercise of federal transmission siting authority by acting on a siting application within one year of its submission or by creating “interstate compacts” for the siting of electric transmission facilities.

To date, the Department of Energy has not designated any area within the SPP footprint as a national interest electric transmission corridor; however, the Department of Energy is required to publish an updated congestion study in 2009 that may designate new national interest electric transmission corridors. Although not currently a national interest corridor, the Department of Energy’s 2006 congestion study named portions of Kansas and Oklahoma as a “Conditional Congestion Area” where future congestion would result if large amounts of new generation were to be developed without simultaneous development of associated transmission capacity.

A. National Corridor Projects

EPAct 2005 required the Secretary of Energy to conduct a study of electric transmission congestion within one year of enactment of EPAct 2005 and every three years thereafter. The report, the Secretary is authorized to designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a “national interest electric transmission corridor.” The Secretary is required to consult with affected


6 In determining whether to designate a national interest electric transmission corridor, the Secretary may consider whether: (a) the economic vitality and development of the corridor or the end markets served by the corridor may be constrained by lack of adequate or reasonably priced electricity; (b) economic growth in the
states, FERC, transmission organizations approved by FERC, and electric reliability organizations and regional entities established under electric reliability organizations. It is only this designation of a “national interest electric transmission corridor” by the Secretary that triggers FERC “backstop” siting authority – EPAct 2005 did not grant FERC any siting authority for projects outside of designated national interest electric transmission corridors.

The Department of Energy issued its initial congestion study for comment on August 6, 2006. The congestion study identified and classified the most significant congestion areas in the country. Two “Critical Congestion areas” (i.e., areas where the current and/or projected effects of congestion are especially broad and severe) were identified: the Atlantic coastal area from metropolitan New York through northern Virginia (the Mid-Atlantic Critical Congestion Area); and southern California (the Southern California Critical Congestion Area). Four “Congestion Areas of Concern” (i.e., areas where a large-scale congestion problem exists or may be emerging but more information and analysis were needed to determine the magnitude of the problem) were identified: New England; the Phoenix-Tucson area; the San Francisco Bay area; and the Seattle-Portland area. A number of “Conditional Congestion Areas” (i.e., areas where future congestion would result if large amounts of new generation were to be developed without simultaneous development of associated transmission capacity) were identified, including: Montana-Wyoming; Dakotas-Minnesota; Kansas-Oklahoma; Illinois, Indiana, and upper Appalachia; and the Southeast.

On October 5, 2007, the Department of Energy issued an order designating two “national interest electric transmission corridors” including: (1) the Mid-Atlantic Area National Corridor, consisting of all or part of Delaware, Ohio, Maryland, New Jersey, New York, Pennsylvania, Virginia, West Virginia, and Washington, D.C.; and (2) the Southwest Area National Corridor, comprising southern California and western Arizona. At present, these are the only areas where FERC has “backstop” authority to approve siting of transmission projects.

The Department of Energy’s next Congestion Study is due to be released in August 2009.

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7 Id. § 824p(a)(1).
8 Id. § 824p(h)(9)(B).
11 Id. at 57,025–026.
B. Federal “Backstop” Siting

EPAct 2005 granted FERC authority to issue permits for construction or modification of electric transmission facilities located in a national interest electric transmission corridor designated by the Secretary of Energy. However, FERC is only authorized to act on a transmission siting application where FERC determines that:

(1) A state in which the transmission facilities are to be constructed or modified does not have authority to: (a) approve the siting of the facilities; or (b) consider the interstate benefits expected to be achieved by the proposed construction or modification of transmission facilities in the state;

(2) the applicant for a permit is a transmitting utility under the Federal Power Act but does not qualify to apply for a permit or siting approval for the proposed project in a state because the applicant does not serve end-use customers in the state; or

(3) a state commission or other entity that has authority to approve the siting of facilities has: (a) withheld approval for more than one year after the filing of an application seeking approval pursuant to applicable law or one year after the inclusion of the area at issue as a national interest electric transmission corridor, whichever is later; or (b) conditioned its approval in such a manner that the proposed construction or modification will not significantly reduce transmission congestion in interstate commerce or is not economically feasible.

In order to issue a permit for siting and construction or modification of transmission facilities, FERC must also determine that: (1) the proposed facilities will be used for the transmission of energy in interstate commerce; (2) the proposed construction or modification is in the public interest; (3) the proposed construction or modification will significantly reduce transmission congestion in interstate commerce and protects or benefits consumers; (4) the proposed construction or modification is consistent with sound national energy policy and will enhance energy independence; and (5) the proposed modification will maximize, to the extent reasonable and economical, the transmission capabilities of existing towers and structures. EPAct 2005 also specifically indicates that federal transmission siting authority does not preclude an entity from constructing or modifying transmission facilities in accordance with state laws. FERC’s siting authority is merely a “backstop” where a state cannot or does not act on a siting application within one year.

13 There is some ambiguity regarding FERC’s authority to entertain siting applications for facilities located in states like Oklahoma and Louisiana, where state commissions do not exert authority over transmission facility siting. This provision may provide FERC with some jurisdiction over transmission siting authority in these states in the event that any territory in these states becomes designated as part of a national interest electric transmission corridor.
15 Id. §§ 824p(b)(2)–(6).
16 Id. § 824p(f).
Once FERC issues a permit, the permit holder can acquire rights-of-way over private property by exercising eminent domain rights in either the state courts or federal district court in the district where the property is located.\textsuperscript{17}

Significantly, in considering applications for siting permits, FERC must “afford each State in which a transmission facility covered by the permit is or will be located . . . a reasonable opportunity to present their views and recommendations with respect to the need for and impact of a facility covered by a permit.”\textsuperscript{18} Additionally, three or more contiguous states may enter into interstate compacts (subject to Congressional approval) to establish regional transmission siting agencies to: (1) facilitate siting of future electric energy transmission facilities within the states involved; and (2) carry out the electric energy transmission siting responsibilities of the states involved.\textsuperscript{19} Such regional transmission siting agencies must have the authority to review, certify, and permit siting of transmission facilities, including facilities in national interest electric transmission corridors, except for the siting of facilities on federal government property.\textsuperscript{20} Where an interstate compact is in place, FERC’s siting authority arises only if the members of the compact are in disagreement and the Secretary of Energy finds that the states involved have failed to act on the siting application for one year or lack the authority to do so.\textsuperscript{21}

In its Order adopting regulations to implement its EPAct 2005 siting authority, FERC initially interpreted its siting authority to include situations where a state denied a siting application, finding that the use of the language “withheld approval” by Congress contemplated not only situations where a state commission has not been able to act within one year of an application, but also where the state has rejected an application.\textsuperscript{22} However, the United States Court of Appeals for the Fourth Circuit rejected this statutory interpretation, finding that FERC’s siting authority effectively arises in five circumstances:

1. a state in which the transmission facilities are to be constructed or modified does not have authority to approve the siting;
2. a state does not have the authority to consider the expected interstate benefits to be achieved by the proposed project;
3. a permit applicant is a transmitting utility under the Federal Power Act but does not qualify for a permit in a particular state;

\textsuperscript{17} Id. § 824p(e).
\textsuperscript{18} Id. § 824p(d). In its order promulgating regulations for implementing its siting authority, however, the Commission indicated that, while it will consider the views of the states involved, it will not defer to the state siting application requirements. \textit{Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities}, Order No. 689, 2006-2007 FERC Stats. and Regs., Regs. Preambles ¶ 31,234, at P 59 (2006), \textit{reh’g denied}, 119 FERC ¶ 61,154 (2007).
\textsuperscript{19} 16 U.S.C. § 824p(i)(1).
\textsuperscript{20} Id. § 824p(i)(3).
\textsuperscript{21} Id. § 824p(i)(4). We are not aware of the existence of any existing interstate transmission siting compacts. Depending on the outcome of pending legislation that may broaden federal siting authority, the SPP states could consider the formation of interstate compacts for transmission siting.
\textsuperscript{22} Order No. 689 at P 31.
(4) a state commission has withheld approval for more than one year after the filing of an application or the designation of the relevant national interest corridor; or

(5) a state commission has conditioned its approval in such a manner that the proposed construction or modification is not economically feasible or will not significantly reduce transmission congestion in interstate commerce.23

The Fourth Circuit Court held that Congress intended to confer siting authority on FERC “only when a state commission is unable to act on a permit application in a national interest corridor, fails to act in a timely manner, or acts inappropriately by granting a permit with project-killing conditions,”24 but not where a state commission has duly exercised its siting authority and denied a permit application within one year of submission.25

Thus, under current law, a state commission possessing transmission siting authority may effectively prevent the exercise of federal “backstop” siting authority by acting on a state siting application within one year.

To the extent FERC’s limited “backstop” authority comes into play, Part 50 of FERC’s regulations sets forth the procedure for reviewing siting applications for transmission facilities located in national interest electric transmission corridors.26 Before formally filing an application, applicants are required to engage in a pre-filing process, the purpose of which is to identify all potential issues and gather all necessary information in order for FERC to process the formal application once it is filed. In situations where states have primary authority to site the facility, the applicant cannot pre-file its application until the one-year state approval period has completed.27 In other instances (i.e., where the state does not have jurisdiction to act or consider the interstate benefits or the applicant does not qualify to apply for a permit in the state because it does not serve end use customers in the state), the applicant may pre-file the application at any time.28 Where states have primary jurisdiction, applicants must act in good faith to seek state approval within the one-year period,29 and FERC retains the discretion to allow the state proceeding to continue after the one-year period before FERC allows an applicant to commence the pre-filing process.30 FERC characterizes its process as allowing two years for state approval,

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24 *Id. at* 315.
25 *Id. at* 313.
26 18 C.F.R. Part 50.
27 Order No. 689 at P 21.
28 *Id. at* P 21 n.14.
29 *Id. at* P 22.
30 *Id. at* P 31.
the initial one-year period plus the period of time for FERC review of the pre-filed materials and the application.\textsuperscript{31}

During the pre-filing stage, the applicant must inform FERC about the status of the state process(es), and FERC will hold a scoping meeting with the applicant and applicable state commission(s) to discuss coordination of environmental and other reviews.\textsuperscript{32} Given the extensive, independent environmental review required by the National Environmental Policy Act (“NEPA”),\textsuperscript{33} FERC encourages project sponsors and states to work together in an attempt to site the facilities at the state level.\textsuperscript{34} Importantly, FERC also has indicated that it expects to use the information developed in state proceedings “to the maximum extent possible” and that it will consider state findings in rendering a decision on an application.\textsuperscript{35} However, FERC also has said that its decision in siting a facility that is deemed to benefit a broad region will not rest on whether the facility benefits individual states crossed by the facility,\textsuperscript{36} and FERC will not defer to state siting requirements and procedures for siting a facility.\textsuperscript{37}

For projects spanning multiple states, FERC’s jurisdiction may arise only over the portion(s) of the proposed project that qualify for federal siting authority (i.e., a state commission has failed to act or cannot act on the application); however, in such circumstances, FERC will analyze the impact of the entire project, including those parts of the project that are under state jurisdiction, in rendering its permitting decision.\textsuperscript{38} FERC will not determine whether a project triggers its jurisdiction prior to the application process, but will instead rule on jurisdiction in its subsequent order on the merits of the proposed project.\textsuperscript{39}

As part of the pre-filing process, the applicant is required to submit a “participation plan” to facilitate participation from all stakeholders during the FERC process.\textsuperscript{40} “Stakeholder” is

\begin{enumerate}
\item \textit{Id.} at P 31. The Commission has estimated that, at least for extensive projects, the pre-filing process for federal siting of transmission projects could take a year to complete, followed by the formal application review period. \textit{Id.} at P 112.
\item \textit{Id.} at PP 23, 45, 92.
\item 42 U.S.C. § 4321, \textit{et seq.}
\item Order No. 689 at P 115 (characterizing the state siting process as “the most expeditious way to site the facilities.”).
\item \textit{Id.} at PP 124–25. Applicants are permitted to use any information developed during state application proceedings to satisfy the Commission’s application filing requirements. \textit{Id.} at P 181. FERC has not yet re-issued revised regulations in light of \textit{Piedmont}. As a result of \textit{Piedmont}’s holding that FERC may not act where a state has timely acted, it is not clear how FERC could consider state findings on an application.
\item \textit{Id.} at P 132.
\item See, \textit{e.g.}, \textit{id.} at P 139. \textit{Piedmont}’s holding calls into question the continuing force of these earlier FERC statements.
\item \textit{Id.} at P 35.
\item \textit{Id.} at P 32.
\item \textit{Id.} at P 46. Applicants are required to notify all stakeholders, including affected state commissions, within 14 days of commencing the pre-filing process. \textit{Id.} at P 60. The Commission requires notification of any
\end{enumerate}
broadly defined as a federal, state, multistate, tribal, or local agency, any affected non-
governmental organization, or other interested person. Once an applicant commences the pre-
filing process, FERC will begin its scoping and environmental review processes, and will seek 
comments and recommendations from interested stakeholders, including scheduling scoping 
meetings to be held by FERC at various locations along the route of the proposed project. FERC 
will assign a docket number to a pre-filed application; however, interested parties will not 
be permitted to intervene until the application is formally filed at the conclusion of the pre-
filing process. Stakeholders will be able to participate at several stages of the siting process, 
including during the applicant’s initial outreach activities, during FERC’s environmental 
review processes under NEPA during the pre-filing and application processes, and once the 
application has been filed. The applicant is also required to name a point of contact within 
the company to answer general inquiries, and it must make all documents related to the project 
available for public inspection, either in central locations in each county along the project route 
or electronically on the project’s website.

Once the Director of FERC’s Office of Energy Projects determines that sufficient 
information has been collected in the pre-filing process to commence review, the pre-filing 
process ends and the applicant will file an application at which point interested parties may 
formally intervene in the proceeding. After the application has been filed, FERC will issue a

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41 18 C.F.R. § 50.1. The Commission will consider any interested entity or individual to be a “stakeholder.” Order No. 689 at P 61.
42 Order No. 689 at P 47.
43 Id. at P 80.
44 Id. at PP 79, 200.
45 Id. at P 48. Intervention is achieved through the normal Commission process outlined in Rule 214 of the Commission’s rules of practice and procedure. 18 C.F.R. § 385.214. State commissions may file a notice of intervention. Id. § 385.214(a)(2).
46 The Commission expects applicants to have conducted outreach activities at the planning and/or state level prior to commencing the pre-filing process. Order No. 689 at P 76.
47 Once the pre-filing process commences, the Commission will issue a notice of intent to prepare an environmental document, describing the project and potential issues, explaining the Commission’s scoping and environmental review processes, setting a comment date, and listing the schedule of scoping meetings to be held by the Commission at various locations throughout the proposed project route. Id. at P 80.
48 Id. at P 74.
49 Id. at P 83.
50 18 C.F.R. § 50.4(b).
51 Order No. 689 at PP 84, 201. The Commission has not established a time-frame for the pre-filing process. Id. at P 112.
52 Id. at P 85.
draft environmental document and invite stakeholder comment. Once FERC has considered all comments and issues a final environmental document, it will issue an order on the merits of the project, including the proposed project route, and issue or deny a permit to construct the proposed facilities. Parties disagreeing with FERC’s findings may seek rehearing using the rehearing procedures outlined in FERC’s rules of practice and procedure.

Order No. 689 also describes the role of RTOs in the federal transmission siting process. FERC is required to afford “due weight” to the findings of independent entities such as RTOs in determining whether the statutory criteria for approval of a project have been met. FERC has also indicated that much of the information to be included in a system analysis for the proposed project will be developed in consultation with any applicable RTO during the pre-filing process. Applicants are required to submit information for FERC to assess the impact of the proposed facilities on existing transmission system performance, including congestion, power flows, stability and short circuit analyses, and information regarding how long-term regional planning is impacted and how congestion will be impacted. In considering an application, FERC will consider environmental impacts, reliability and transmission system impacts, and alternatives to the project, among other things.

Once a permit is issued, if the applicant cannot otherwise obtain necessary rights-of-way through contract or agreement with the owner of the property, it may exercise the right of eminent domain in either federal or state court. Proceedings in federal court are required to conform as nearly as practicable to the rules and procedures applicable to similar proceedings in the state court of the state in which the property is located.

FERC thus has extensive regulations delineating in detail how it will process applications under its “backstop” siting authority, including provision for extensive participation by the states and other stakeholders. Nonetheless, in light of the Piedmont case, under current law there is unlikely to be any significant use of FERC’s “backstop” authority. As noted, timely siting decisions by the states can effectively eliminate any exercise of federal authority. As discussed below, however, pending legislation could alter the effect of Piedmont and bring FERC’s “backstop” authority and these regulations back into play.

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53 Id. at P 88.
54 Order No. 689 at P 89.
55 Id. at P 44.
56 Id. at P 99. The Commission will review all stakeholder processes conducted by the applicant, including applicable RTOs and ISOs, in determining whether to issue a construction permit. Id. at P 189.
57 Id. at P 188.
58 Id. at P 191.
60 Id. § 824p(e)(3).
V. Pending Federal Legislation

Several significant pieces of energy legislation have been introduced in the 111th Congress; however, legislative efforts in both chambers have focused on creating a single, comprehensive energy bill. The principle House bill, H.R. 2454, currently contains limited provisions addressing federal transmission planning and provides FERC with transmission siting authority in the Western Interconnection only. It was passed by the House by a vote of 219-212 on June 26, 2009. The Senate measure, which addresses not only transmission planning but also federal transmission siting authority throughout the United States, has been approved by the Senate Energy and Natural Resources Committee and is proceeding to the full Senate. Both pending bills address matters that could significantly impact transmission planning in SPP.61

A. Senate Legislation – American Clean Energy Leadership Act of 2009

(Senate Energy and Natural Resource Committee Draft)

The main legislative vehicle for energy reform in the Senate is the American Clean Energy Leadership Act of 2009, which has not yet been formally introduced but was crafted from several individual bills by the Senate Energy and Natural Resources Committee. The Senate energy bill addresses, among other things, enhanced federal electric transmission planning and siting authority and cost allocation. The legislation authorizes FERC to approve applications for siting of “high-priority national transmission projects” (operating at or above 345-kV for alternating current and at or above 300-kV for direct current) that are included in an “Interconnection-wide transmission plan.” The bill requires FERC to coordinate regional and sub-regional plans into Interconnection-wide plans for the Eastern Interconnection and the Western Interconnection.

Under the measure, states would have the first opportunity to site a high-priority national transmission project; however, if after one year the state fails to act, rejects an application, or places unreasonable conditions on its siting approval, FERC would have authority to siting of the transmission facility. This bill would therefore modify the Piedmont holding and permit FERC to site a facility that a state has rejected. The bill requires the planning processes to take renewable generation and location-constrained resources into consideration, but does not require national transmission projects to be specifically designated to serve renewable resources. The bill would require FERC to adopt national electricity grid planning principles addressing coordination among planning entities and requiring consideration of location-constrained resources (including renewable generation), demand side resources, and costs to consumers, among other factors.

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61 Proposed legislation has covered the gamut of energy issues including renewable energy generation, federal transmission siting authority, climate change, increased domestic energy and fuel production, and other issues. For instance, while not directly applicable to the issue of transmission siting, Arkansas Rep. Mike Ross recently introduced H.R. 3009, legislation to diversity U.S. energy sources by: (1) encouraging domestic exploration and production of oil and natural gas by opening up more domestic U.S. territory to exploration, including the Arctic National Wildlife Refuge and Outer Continental Shelf; and (2) using lease and royalty payments from the sale of oil and gas leases to create an “American-Made Energy Trust Fund” to provide incentives for alternative and renewable energy projects. Given the significant differences between the main legislation in the House and Senate, it is unclear which aspects of other pending bills, such as Congressman Ross’s bill, may be included in any comprehensive energy measure.
Under the Senate bill, FERC also is required to establish by rule an appropriate methodology for cost allocation for high-priority national transmission projects, including allocation of costs to all load-serving entities within all or part of a region. Costs cannot be socialized in this manner, however, “unless the costs are reasonably proportionate to measurable economic and reliability benefits.”

The Senate bill also includes language creating a national renewable electricity standard requiring utilities to supply 15% of their power by renewable energy resources by 2021, and provides greater market oversight authority to FERC including the ability to issue cease and desist orders and to temporarily modify electricity rates and terms in “emergency” circumstances (where disturbances in wholesale electric markets could disrupt service or result in excessive price fluctuations), among other things. The legislation also would require FERC to develop interconnection rules for small-scale distributed generation, including residential distributed generation.

Other provisions of the bill include appliance efficiency, energy efficiency building code standards, “green” work force training, development of a clean energy bank, encouragement of and indemnity from liability for carbon sequestration demonstrations, creation of a refined products reserve, expanded Department of Energy authority in energy markets, incentives for distributed generation and small-scale energy production, expanded data collection authority for the Energy Information Agency, and other matters.

The bill was approved 15-8 by the Senate Energy and Natural Resources Committee and is expected to be introduced on the floor of the Senate this summer. The Senate Democratic leadership has expressed its intent to combine comprehensive energy legislation along with climate change legislation; however, to date, no comprehensive climate change legislation has advanced through the committee process. Most likely, these efforts will not culminate until this fall.


Comprehensive energy and climate change legislation passed the House of Representatives on June 26, 2009 by a vote of 219-212. H.R. 2454, “The American Clean Energy and Security Act of 2009,” is designed to: (1) promote renewable energy, carbon capture and sequestration technologies, low-carbon fuels, clean electric vehicles, and smart grid and electricity transmission infrastructure; (2) increase efforts to promote energy efficiency across all sectors of the economy, including electric and natural gas distribution utilities, buildings, appliances, transportation, and industry; (3) establish a cap-and-trade system for greenhouse gases to reduce emissions of heat-trapping pollutants; (4) provide financial assistance to protect consumers and industry from the costs imposed by the legislation and promote green jobs during the transition to a clean energy economy; and (5) grant FERC transmission siting authority in the Western Interconnection.

While the main focus of H.R. 2454 is to address global warming, the bill contains several provisions directly applicable to the energy industry. At present, H.R. 2454 does not contain any
language granting expanded federal transmission siting authority to FERC or any other federal entity in the Eastern Interconnection (including SPP); however, the bill does provide FERC with authority to issue permits for the siting of transmission facilities in the Western Interconnection if a state commission does not issue a decision on or denies an application seeking siting approval for a facility within one year of submission or imposes conditions that unreasonably interfere with the development of the facility. In order to qualify for federal siting authority, the proposed facility must be identified as part of a regional or Interconnection-wide electric grid plan that was submitted to FERC and developed in accordance with national grid planning principles adopted by FERC, the facility must be “identified as needed in significant measure to meet demand for renewable energy in such plans,” and the facility must be multistate in nature.

Additionally, the bill requires FERC to establish national transmission planning principles and to review transmission plans from regional planning entities that agree to incorporate national electricity grid planning principles in their electric grid planning, and also requires FERC to coordinate with the U.S. Department of Interior, the National Oceanic and Atmospheric Administration, and coastal states to study the siting of offshore renewable energy facilities and related transmission lines.

The legislation also creates an office of consumer advocate within FERC to: (1) represent (and appeal on behalf of) energy customers on matters concerning rates or service of public utilities and natural gas companies before FERC, other federal agencies, and the courts; (2) monitor and review energy customer complaints and grievances concerning rates and services for companies under FERC’s jurisdiction; (3) investigate services provided by and rates charged by utilities under FERC’s jurisdiction; (4) develop means to ensure that the interests of consumers are represented before FERC to the maximum extent practicable; and (5) collect and analyze data, prepare reports, and issue recommendations. H.R. 2454 also creates a national renewable energy standard requiring utilities to meet 20% of their load with renewable energy by 2020, to be overseen by FERC, among other things.

C. Potential Impacts of Federal Legislation on SPP Planning

While it is premature to predict the final outcome of the ongoing legislative debate, the pending legislation, some form of which may be enacted this year, indicates that new federal authorities could have implications for the SPP planning process. These include:

- Potential for FERC involvement in high-voltage transmission planning or Interconnection-wide planning, at least to the extent of “coordinating” regional plans to develop “Interconnection-wide” plans;
- Greater emphasis on renewable generation through a national renewable electricity standard, giving rise to greater transmission planning emphasis on connecting location-constrained renewable generation to load centers;
- Potential regulations for cost allocation of national interest transmission projects or Interconnection-wide projects, which could impact existing SPP cost allocation methodologies; region-wide socialization of transmission costs could require demonstration of “measurable” region-wide benefits; and
• Modification of the *Piedmont* holding and expansion of federal “backstop” siting authority where states reject transmission siting applications for high-voltage transmission projects of national interest.

There are significant differences between the House and Senate versions of the legislation (such as whether federal authority will be limited to the Western Interconnection or will more broadly encompass the Eastern Interconnection as well), and at this time it is unclear how the differences may be resolved. The transmission aspects of the legislation also are secondary to the more controversial “cap-and-trade” provisions. Whether new transmission legislation emerges may depend on the outcome of the cap-and-trade debate.

## VI. Conclusion

SPP’s governing documents explicitly recognize the role of state and federal siting laws and regulations in the transmission planning process. Implementation of the STEP is “subject to” the “siting, permitting, and environmental” constraints imposed by “state, local and federal laws and regulations.”

Under current law, siting of electric transmission facilities remains primarily under the jurisdiction of state regulatory commissions. While EPAct 2005 granted FERC “backstop” authority to approve siting of transmission facilities, FERC’s authority is limited to designated “national interest electric transmission corridors,” and arises only when a state is unable to consider a project or fails to act on an application within one year. In situations where FERC’s authority is triggered, EPAct 2005 and Order No. 689 require FERC to consider the findings and conclusions of states throughout the transmission siting approval process. States have the ability to avoid federal involvement by acting on a transmission siting application within one year of its submission.

Congress is considering legislation that potentially will expand FERC’s transmission siting authority over high-voltage projects, including possibly authorizing FERC to modify the outcomes of state decisions regarding these facilities. However, if Congress grants broader transmission siting authority to FERC, FERC may use its existing but dormant siting regulations under EPAct 2005 to consider new transmission siting applications. These regulations already recognize the importance of state participation in the transmission siting process including: (1) requiring applicants to involve state commissions in the pre-filing and application process; (2) coordinating environmental reviews with state commissions; and (3) inviting state regulatory commissions to intervene and offer comment throughout the process. Pending legislation also preserves the ability of states to consider siting applications before FERC authority is triggered, preserving to a significant extent the primary authority that states have traditionally had over transmission siting. FERC’s order adopting the siting regulations that likely will be used for any federal applications indicates FERC’s intent to use information from state proceedings “to the maximum extent possible” and that FERC will consider state findings in its decisions.

Under pending legislation, SPP’s decisions in the STEP process, which take into account the views of stakeholders including state commissions, likely will carry significant weight. It appears the legislation also may adopt a “bottom up” approach, coordinating regional plans such
as the STEP into Interconnection-wide plans. FERC’s existing siting regulations already afford “due weight” to the findings of RTOs and that likely will continue.

Wright & Talisman, P.C.
July 20, 2009
A. Arkansas

For transmission siting authorizations, Arkansas Law distinguishes between “major utility facilities” (transmission lines and associated facilities with a design voltage of at least 100-kV if the transmission line is more than 10 miles in length, or transmission lines and associated facilities with a design voltage of at least 170-kV for lines more than one mile in length)\(^1\) and other, non-major transmission facilities, with major transmission facilities undergoing more rigorous review than non-major projects. Modifications to existing facilities to replace, upgrade, or modernize existing lines and associated equipment do not require additional authorizations if they do not exceed existing rights-of-way.\(^2\)

Applicants are required to submit information showing: (1) that the proposed construction is or will be required by the public convenience and necessity; (2) the proposed location or route; (3) the manner in which the facilities will be constructed; (4) maps specifying the route to be followed in constructing the new transmission line, the location of nearby airports, and applicable allocation boundaries; (5) cost estimates and related data; and (6) the proposed method of financing.\(^3\) Applicants seeking to construct major utility facilities are also required to submit information regarding: (1) a general description of the location and type of transmission line and associated facilities; (2) a general description of any reasonable alternative locations or routes considered; (3) the need and reasons for construction of the transmission line and associated facilities; (4) the estimated construction cost; (5) the method of financing and reasonable alternative methods of financing, including the comparative merits and demerits of each alternative financing method; (6) a discussion of the merits and demerits of financing the project through the issuance of state or federal tax-exempt bonds (if applicable); (7) the projected economic and financial impact on the applicant and the local community; (8) the estimated effects on energy costs to the consumer; (9) an environmental impact statement setting forth the environmental impact, any adverse environmental effects that cannot be avoided, a statement of the reasons why the proposed location and production processes were chosen over the identified alternatives, and any irreversible and irretrievable commitments of resources that would be involved in the proposed construction; and (10) such other information of an economic or environmental nature that the applicant may consider relevant.\(^4\) Applicants seeking to construct transmission lines and related facilities in a national interest electric transmission corridor are also required to submit a discussion of the interstate benefits to be achieved by the proposed construction.\(^5\)

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\(^2\) Id. §§ 23-3-201(a)(2), 23-18-510(a).
\(^3\) Arkansas Public Service Commission Rules of Practice and Procedure § 7.04 (Certificates of Public Convenience and Necessity – Electric Utilities).
\(^5\) Id. § 23-18-511(9).
In approving an application for siting and construction of a major utility facility, the Arkansas Public Service Commission (“APSC”) is required to make findings and issue an order determining: (1) the basis of the need for the transmission project; (2) that the transmission line will serve the public interest, convenience, and necessity; (3) the nature of probable environmental impacts; (4) that construction and the location of the proposed transmission line represents an acceptable adverse environmental impact; (5) the nature and extent of probable economic impact of the construction and siting of the proposed transmission line and associated facilities; (6) that construction of the proposed project is not inconsistent with the filed and known plans of other electric utilities serving the state; (7) that the proposed location or route conforms as closely as practicable to applicable state, regional, and local laws; and (8) that the transmission facilities to be constructed will meet or exceed applicable construction standards.\(^6\) For projects proposed in national interest electric transmission corridors, the APSC is also required include in its order an assessment: (1) of the interstate benefits expected to be achieved by the proposed construction or modification of the major electric transmission facility; and (2) that any conditions attached to a certificate for construction or modification of transmission facilities to be located within a national interest electric transmission corridor do not interfere with the reduction of electric transmission congestion in interstate commerce and do not render the project economically infeasible.\(^7\)

The APSC is required hold a public hearing on an application no sooner than 40 days and no later than 180 days after the filing of the application; and is required to issue an order on the application “as expeditiously as practicable.”\(^8\)

**B. Kansas**

Applicants for construction of transmission facilities in Kansas are required\(^9\) to submit an application to the Kansas Corporation Commission (“KCC”) prior to beginning site preparation or construction, detailing: (1) the proposed location; (2) the names and addresses of the landowners of record whose land is proposed to be acquired in connection with the construction of or is located within 660 feet of the center line of the easement where the line is proposed to be located; and (3) such other information as may be required by the KCC.\(^10\) The KCC is required to conduct a public hearing in one of the counties through which the proposed transmission line is expected to traverse within 90 days after receiving an application, to determine the necessity for and reasonableness of the location of the proposed electric transmission line.\(^11\) The KCC

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\(^6\) *Id.* § 23-18-519(b).

\(^7\) *Id.* §§ 23-18-519(b)(11)–(12).

\(^8\) *Id.* § 23-18-516(a)(1).

\(^9\) The Kansas Siting Act does not apply to: (1) portions of any electric transmission line to be constructed on an easement where there currently exists one or more electric transmission lines if the easement is not within the corporate limits of any city; (2) portions of any electric transmission line to be constructed on property adjacent to a right-of-way along a four-lane controlled access highway; or (3) any electric utility that complies with the provisions of the National Environmental Policy Act of 1969 regarding the siting of electric transmission lines. KSA § 66-1, 182 (2008).

\(^10\) *Id.* § 66-1, 178(a).

\(^11\) *Id.* § 66-1, 178(b).
must issue a final order on the application within 120 days of the filing of the application,\textsuperscript{12} taking into consideration the benefit to both consumers in Kansas and consumers outside the state, as well as economic development benefits in Kansas.\textsuperscript{13}

C. Louisiana

Louisiana state law does not require a utility to obtain siting approval from the Louisiana Public Service Commission ("LPSC") prior to constructing a transmission facility in the state, and, while state courts have determined that the LPSC has broad "plenary" authority over electric utilities,\textsuperscript{14} the LPSC has not issued regulations requiring utilities to seek approval for transmission siting. However, construction of electric public utility facilities is limited by the statutory "three hundred foot rule," which indicates that electric public utilities cannot construct or extend facilities, or furnish or offer to furnish electric service, to any point of connection which is being served by another electric public utility or within three hundred feet of an existing electric line of another electric public utility.\textsuperscript{15}

Additionally, public utilities are prohibited from constructing new facilities or extending existing facilities in cities “unless and until the governing authority of the city certifies that public convenience and necessity require the same.”\textsuperscript{16} Utilities are required to obtain property or rights-of-way either from landowners through voluntary agreement or eminent domain, which could further involve state and local government agencies in the process.

D. Missouri

The Missouri Public Service Commission ("MoPSC") is empowered with issuing certificates of convenience and necessity for the construction of electric plants, including electric transmission facilities ("line certificate authority"),\textsuperscript{17} and for electric utility franchise areas ("area certificate authority").\textsuperscript{18} Line certificates may be granted without a local franchise being granted, and area certificates entitle the electric utility to construct transmission lines within the certificated franchise area without having to obtain separate line certificates or additional approval from the MoPSC.

\textsuperscript{12} Id. § 66-1, 178(d).
\textsuperscript{13} Id. § 66-1, 180. The KCC may issue or withhold the permit or condition the permit to protect the rights of all parties and the general public. Id.
\textsuperscript{14} See, e.g., La. Power & Light Co. v. La. Pub. Serv. Comm’n, 609 So. 2d 797, 800 (La. 1992) (citing La. Const. art. IV, § 21(B)).
\textsuperscript{15} La. Rev. Stat. Ann. § 45:123 (2009). Under the statute, “electric line” means both transmission and distribution lines. Id. § 45:123(B). Given that the three hundred foot rule applies to electric service furnished to “points of connection,” it generally does not preclude the building of transmission lines located within three hundred feet of other existing transmission lines.
\textsuperscript{16} Id. § 33:4406. City approval for extensions of existing facilities are only required where the extension “will cost over two percent of the rate-making value of the property at the time the extension or addition is made.” Id.
\textsuperscript{17} Mo. Rev. Stat. § 393.170(1) (2009).
\textsuperscript{18} Id. § 393.170(2).
Upon application for a certificate of convenience and necessity, the MoPSC is authorized to grant approval if, after due hearing, it determines that the construction or exercise of the right, privilege, or franchise sought is necessary or convenient for the public service.\textsuperscript{19} MoPSC may also impose conditions upon the certificate as it may deem reasonable and necessary.\textsuperscript{20} The Missouri Revised Statutes do not specify any criteria for the MoPSC to consider or define what is “necessary or convenient,”\textsuperscript{21} nor do they impose any deadline for MoPSC action on an application.

The MoPSC’s procedural rules outline certain criteria an applicant must include in its application for an area or line certificate. For area certificates, the applicant must include: (1) a statement regarding other similar utility service provided in the area; (2) information regarding the identity of landowners and residents in the proposed franchise area; (3) a legal description of the area to be certificated; (4) a plat of the proposed area; (5) a feasibility study containing plans and specifications for the utility system and estimated cost of the construction of the utility system during the first three years of construction; (6) plans for financing; and (7) proposed rates and charges and an estimate of the number of customers, revenues and expenses during the first three years of operations.\textsuperscript{22} For line certificates, the MoPSC requires: (1) a description of the route of construction and a list of all electric and telephone lines, railroad tracks, and underground facilities that the proposed construction will cross; (2) construction cost information and specifications; and (3) plans for financing.\textsuperscript{23} Applications for both area and line certificates also must present facts demonstrating that the granting of the application is required by the public convenience and necessity.\textsuperscript{24}

E. Nebraska

Nebraska electric service is provided exclusively by public power entities and there is no process or authority for private electric utilities to build transmission facilities in the state. Two entities, the Nebraska Power Review Board ("NPRB") and the Nebraska Public Service Commission ("NPSC") have jurisdiction over certain aspects of transmission facility siting. A utility seeking to construct new transmission facilities in Nebraska must first reach agreement with other affected transmission owners regarding what facilities are needed.\textsuperscript{25} The builder must

\textsuperscript{19} Id. § 393.170(3).
\textsuperscript{20} Id.
\textsuperscript{21} Missouri courts, however, have determined that a finding that a facility or franchise is “necessary and convenient” requires at least a determination that the facility or franchise is “adequate,” which includes assessing the relative experience of competing suppliers of the service. State ex rel. Ozark Elec. Coop. v. Pub. Serv. Comm’n of the State of Mo., 527 S.W.2d 390, 394 (Mo. Ct. App. 1975).
\textsuperscript{23} Id. § 240-3.105(1)(B).
\textsuperscript{24} Id. § 240-3.105(1)(E).
\textsuperscript{25} Neb. Rev. Stat. § 70-1002.03 (2009).
then seek approval from the NPRB by applying for a certificate of convenience and necessity.\textsuperscript{26} The NPRB Rules of Practice and Procedure outline the application requirements including: (1) a map showing all transmission and distribution lines within one mile of the proposed facility; (2) a statement of how the applicant will provide service at its “low [sic] overall cost as possible consistent with sound business practices;” and (3) construction cost information, whether the cost will be paid in part by any customer, and if so, the amount of the customer’s contribution.\textsuperscript{27}

The NPRB must schedule a hearing within 30 days (or within 90 days if the applicant requests an extension and demonstrates good cause), and must render its decision within 30 days of the hearing.\textsuperscript{28} To issue a certificate, the NPRB must determine that the facilities will serve the public convenience and necessity, and that the applicant can most economically and feasibly supply the electric service without unnecessary duplication of facilities or operations.\textsuperscript{29}

NPSC approval is required for all transmission lines located outside of incorporated cities where the line crosses a highway or railroad track or is to be located within a certain distance (depending on the voltage of the proposed line) of existing electrical, communication, or railroad signal lines or airports.\textsuperscript{30} In such instances, the applicant is required to provide maps and engineering specifications regarding the proposed facility.\textsuperscript{31}

\textbf{F. New Mexico}

Under New Mexico statute and the rules of the New Mexico Public Regulation Commission (“PRC”), utilities seeking authorization to construct transmission lines operating at or above 230-kV and related facilities are required to obtain a certificate of public convenience and necessity,\textsuperscript{32} a location permit,\textsuperscript{33} and a right-of-way width determination (where the necessary right-of-way is wider than 100 feet).\textsuperscript{34} When reviewing an application for a location permit, the PRC may consider: (1) existing plans of the state, local government, and private entities for other developments at or in the vicinity of the proposed location; (2) impacts on fish, wildlife, and plant life; (3) potential noise emission levels and interference with communication signals; (4) the proposed availability of the location to the public for recreational purposes, consistent with safety considerations and regulations; (5) existing scenic areas, historic, cultural, or religious

\begin{itemize}
\item \textsuperscript{26} Id. § 70-1012. Utilities are not required to apply for certificates to extend facilities within the supplier’s own service area or within one-half mile outside its service area if all of the other owners of transmission facilities within one-half mile consent to the extension in writing. \textit{Id}.
\item \textsuperscript{27} 285 Neb. Admin. Code § 2-004 (2008).
\item \textsuperscript{28} Neb. Rev. Stat. § 70-1013 (2009).
\item \textsuperscript{29} \textit{Id.} § 70-1014. The NPRB is responsible for approving the siting of transmission facilities but has no jurisdiction over rates. \textit{Id.} § 70-1002.03.
\item \textsuperscript{30} \textit{Id.} §§ 75-701–724.
\item \textsuperscript{31} 291 Neb. Admin. Code § 7-002.02 (2009)
\item \textsuperscript{33} \textit{Id.} § 62-9-3(A).
\item \textsuperscript{34} \textit{Id.} § 62-9-3.2.
\end{itemize}
sites and structures or archaeological sites at or in the vicinity of the proposed location; and (6) additional factors that require consideration under applicable federal and state laws pertaining to the location.\(^{35}\)

The PRC is required to act on an application for a certificate of public convenience and necessity and a location permit within nine months of submission of the application, but may grant itself a six-month extension for good cause shown.\(^{36}\) Utilities are required to comply with all local permitting requirements; however, if the local authority does not act within 240 days or does not approve the permit application, the applicant may file for approval with the PRC.\(^{37}\) The PRC cannot approve a permit for a project that violates existing state, county, or municipal land use statutes or administrative regulations unless the PRC finds that the regulation is unreasonably restrictive and compliance with the regulation is not in the interest of the public convenience and necessity.\(^{38}\)

**G. Oklahoma**

The Oklahoma Corporation Commission ("OCC") does not have authority over the siting of transmission facilities in the state. Under Oklahoma law, companies authorized to furnish electricity service in the state have the same right of eminent domain as applies to railroads operating in the state.\(^{39}\) A party seeking to exercise eminent domain must petition the district court for the district in which the property is located,\(^{40}\) and must include in its petition a statement indicating: (i) that it is authorized to exercise the power of eminent domain and it has been unable to make a voluntary purchase of the property or right-of-way in question; (ii) the owner of the property and the specific property in question; and (iii) that the specific property sought to be taken is necessary for a purpose for which the power of eminent domain may be exercised.\(^{41}\)

In a recent case involving an application by a transmission-only electric utility to provide wholesale bulk electricity transmission services within the state of Oklahoma, the OCC adopted an Administrative Law Judge’s recommendations that the OCC “find that no determination by the [OCC] that additional transmission capacity is needed in Oklahoma is required, prior to any company building transmission lines in Oklahoma,” and that “SPP will make the decision regarding which entity will install and maintain transmission lines necessary for the efficient and

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\(^{35}\) *Id.* § 62-9-3(M).

\(^{36}\) *Id.* §§ 62-9-1(C) and 62-9-3(K). If the location permit application is filed while the application for a certificate of public convenience and necessity is pending, the PRC must act on the location permit within ninety days after the certificate of public convenience and necessity is granted. *Id.* § 62-9-3(K)(3).

\(^{37}\) *Id.* § 62-9-3(H).

\(^{38}\) *Id.* § 62-9-3(G).


\(^{40}\) *Id.* at tit. 66, § 53.

cost effective distribution of electricity for the use of [Oklahoma Gas & Electric Company’s] customers.”

H. Texas

The Public Utilities Regulatory Act (“PURPA”) prohibits electric utilities from directly or indirectly providing service to the public unless the utility first obtains a certificate of public convenience and necessity from the Public Utility Commission of Texas (“PUCT”). Utilities are not required to obtain a certificate for: (1) extensions into contiguous territories that do not receive similar service from another electric utility and are not in another electric utility’s certificated area; (2) extension in or to territory that the utility serves or is authorized to serve; or (3) operation, extension, or service in progress on September 1, 1975.

In reviewing a certificate application, the PUCT considers: (1) the adequacy of existing service; (2) the need for additional service; (3) the effect of granting the certificate on the recipient and any electric utility service in the proximate area; (4) impacts to community values, recreation and park areas, historic and aesthetic values, and environmental integrity; (5) the probable improvement of service or lowering of costs to consumers; and (6) the effect of granting the certificate on the ability of the state to meet renewable energy goals. Under its Substantive Rules, the PUCT also considers the needs of the interconnected transmission system to support a reliable and adequate network and to facilitate robust wholesale competition, and gives “great weight” to recommendations from “essential organizations” (i.e., independent system operators) or written documentation that the proposed facility is needed to connect a new transmission service customer. PUCT transmission line routing decisions are based on whether the proposed route: (1) utilizes existing compatible rights-of-way, including vacant positions on existing multiple-circuit transmission lines; (2) parallels existing compatible rights-of-way; (3) parallels property lines or other natural or cultural features; and (4) conforms with the policy of prudent avoidance, which seeks to limit exposure to electric and magnetic fields.

The PUCT is required to render its certificate decision within one year of the application; however, the PUCT has reserved the right to extend the one-year period for good

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44 Id. § 37.052(a). Extensions of service are only allowed to interconnect to existing facilities or solely to transmit electric utility services from an existing facility to a customer of retail electric utility service. Id. § 37.052(b).
45 Id. § 37.056(c).
47 Id. § 25.101(b)(3)(B). These considerations are tempered where grid reliability or security dictate otherwise. Id.
Projects that have been formally designated by an “essential organization” as critical for the reliability of the transmission system must be considered on an expedited basis, with the PUCT issuing a decision within 180 days of receiving a completed application. Expedited proceedings are also afforded to transmission lines serving “competitive renewable energy zones” designated by the PUCT and to uncontested applications.

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49 PUCT Subst. R. § 25.101(b).
50 Id. § 25.101(b)(3)(D).
52 PUCT Subst. R. § 25.101(b)(3)(C). The PUCT must act on an uncontested application that is complete and meets all filing criteria within 80 days of filing.
The Synergistic Planning Project

New, Proactive Efforts to Improve Transmission Planning and Cost Allocation for the SPP Region

*Draft: Excerpts from “ITP Roadshow” for state regulators*

Purpose

- Communication/discussion tool for Synergistic Planning Project
- Condensed version of longer presentation
- Will vet with members and CAWG before use
- Contents will continue to evolve
Overview

- SPP’s current transmission planning processes
- Synergistic Planning Project:
  - Integrated Transmission Planning
  - Priority Projects
  - Cost Allocation and Cost/Benefit Analysis
- Role of regulators

Synergistic Planning Project Team (SPPT)

- SPP recommended formation of SPPT to:
  - Look for opportunities to improve transmission planning and cost allocation
  - Think creatively – unencumbered by Tariff or other limitations
Synergistic Planning Project Team Members

- Paul Suskie; Chairman, Arkansas Public Service Commission
- Barry Smitherman; Chairman, Public Utility Commission of Texas
- Kelly Harrison; Vice President – Transmission Operations and Environmental, Westar Energy
- Ricky Bittle; Vice President - Planning, Rates and Dispatching, Arkansas Electric Cooperative Corporation
- Rob Janssen, President and General Manager, Dogwood Energy
- Ric Abel; Managing Director, Prudential Capital Group
- Carl Monroe; Executive Vice President and COO, SPP
- Mark Rossi, Accenture, facilitation and administration

Components of SPPT Report

- Integrated Transmission Plan
- Priority Projects
- Cost Allocation
What is Integrated Transmission Planning?

- **Major Objective:** Design transmission backbone to connect load centers to low-cost generation
- **Other Objectives:**
  - Improve connections between SPP’s east and west regions
  - Make transmission an enabler rather than constraint
  - Strengthen ties to Eastern and Western Interconnections

ITP Milestones

- August: ESWG approves Priority Projects economic metrics
- August - October: SPP visits with state regulators
- September: ESWG/TWG reach consensus on ITP process
- October: CAWG completes and RSC approves cost allocation methodology
- October: BOD approves ITP process and Priority Projects
- January 2010: BOD approves Tariff language for ITP and cost allocation
- 1Q 2010: FERC approves Tariff language for ITP and cost allocation
The Road to Financial Transmission Congestion Cost Hedging in SPP

The Recommendation

- On June 17th the Congestion Hedging Task Force (CHTF) made a recommendation to Market Working Group (MWG) that SPP adopt a financial mechanism for hedging transmission congestion costs in the future markets.
- MWG adopted this approach
- MOPC has been informed
Who Is the CHTF?

- CHTF representatives included:
  - State regulatory staff
  - Load-serving members
  - Transmission Owning members
  - Power Marketers
  - Merchant Generators
  - SPP Staff
  - Industry consultants

Why Do Anything?

- The future market cost/benefit study shows an opportunity for significant savings through an SPP-wide centralized unit commitment
  - Estimated at $100M/yr = $BIG$
  - Reminder: Unit commitment must be a DA process due to physical plant characteristics
Decision Process - Is Change Necessary?

- To realize the $BIG$ benefits SPP will implement a DA energy market, with centralized unit commitment

But...
- Existing process impedes full use of a centralized commitment process
- Today, MPs use their own Day Ahead (DA) commitment and schedules as a hedge against cost to serve load – "my unit serves my load, so I know the cost"

Change IS Necessary

- Realizing the $BIG$ savings will require change –
- Specifically, generation owners must turn the commitment decisions for their own units over to the market.
Change is Necessary – HOW?

How do we convince the MP to let someone else make commitment decisions for their resources, and them live with the results?

By indemnifying them from the cost impact of those decisions.

Change is Necessary – HOW?

Developing and settling a financially binding Energy solution and Congestion hedge in the DA time frame will provide price assurance.

That price assurance will allow Load Serving Entities to turn over the generation commitment decision and economically offer into the DA market
Wide Range of Initial Positions in CHTF

- FTRs - No way – Never!
- Hedges must be physical
- FTRs - the only way to go – why don’t we already have them?
- Everywhere in between
- All meeting participants displayed an open mind and shared a desire to learn, understand and make the best decision

What was the CHTF Decision Process?

- Thorough, reasoned approach
- Reviewed the decisions of other RTOs
- Analyzed numerous complex examples
  - Engaging in these discussions and extensive “what-ifs” provided the most learning
- Asked questions like:
  - How would your company evaluate a recommendation?
  - What would the ultimate impact be to rate payers?
Decision Process - Areas of Concern

- How comparable is it to your hedge today?
- What is the availability period (Hourly, Daily, Monthly, Yearly)?
- Does the mechanism:
  - promote full use of the transmission system?
  - increase the capability to trade energy bilaterally?
  - support the concept of energy trading hubs?
  - allow a participant to place a value on the right?
  - allow the rights to be traded?
  - require the scheduling of Native Load?
  - Minimize the need for uplift?
  - Provide transparent results?
- How complex is it?
- What are the system changes necessary with each mechanism?
- Does the mechanism provide any incentive or disincentive for transmission expansion?

Decision Process

Inescapable Conclusion…

- There is no single perfect solution
- Every option involves compromise and tradeoffs
Congestion Hedging Examples

Review Fundamental Elements of LMP Market

- ALL load pays the LMP at its location
  - Regardless of any other arrangements

- ALL Generation is paid the LMP at its location
  - Regardless of any other arrangements

Congestion Hedging Examples

Simple “System” Description:

- One Market Participant with...
  - One Load Location: 500 MW
  - One Cheap Generator: 500 MW @ $20
  - One Expensive Generator: 500 MW @ $70
Simple “System” Diagram

Two generators and one load

500 MW
$70 / MWh

g E

500 MW
$20 / MWh

g C

Load=500 MW

All generation and load is offered into the DA market

Scenario N

DA, No congestion, All of gen C is deployed

LMP= $X

500 MW
$70 / MWh

g E

0

500

Paid LMP

Load=500 MW

LMP = $X

500 MW
$20 / MWh

g C

500

Pays LMP

No Congestion → LMP at all locations is the same
Regardless of LMP magnitude, the dollars paid at load equal dollars received at generation
Net transaction with market = zero
Cost to serve load is just the fuel cost at gen C
The effect is as if gen C energy was delivered to the load.
**Scenario C (Congestion)**

**DA, WITH congestion, Gen C is Limited**

*LMPs are assumed for illustration purposes*

<table>
<thead>
<tr>
<th>Load (500 MW)</th>
<th>LMP = $70</th>
</tr>
</thead>
<tbody>
<tr>
<td>LMP = $70</td>
<td>500 MW</td>
</tr>
<tr>
<td>LMP = $20</td>
<td>500 MW</td>
</tr>
</tbody>
</table>

With Congestion → LMP varies by location

- $ paid at load = 500 x $70 = $35,000
- $ received at gen E = 100 x $70 = $7,000
- $ received at gen C = 400 x $20 = $8,000

Net market transaction is to PAY (35 - 8 - 7) = $20,000

Cost to serve load is own fuel cost **PLUS $20,000** in Congestion Cost.

A hedge is needed.

---

**Hedges can take three basic forms.**

- **Pro-Rata**
- **Transactional (Physical)**
- **Independent (Financial)**
Ruled out Pro-rata approach early

- In the Pro-rata method congestion over-collection is returned to the MPs through some static formula.
  - Consistent with postage stamp transmission cost allocation
- The hedge has no relation at all to the commitment or operational decisions
- All congestion costs are spread as uplift (RNU in today’s EIS market)

Analysis Review – Transactional (aka physical)

- Tied to actual operations
- Value as a credit against the congestion charge on a schedule (transaction)
  - Similar to EIS today – schedules avoid Imbalance
- Could apply to both firm and non-firm schedules
- Simultaneous Feasibility is assured in near real-time
  - Schedules are cut if infeasible
Analysis Review – **Independent**
(aka financial)
- Not necessarily tied to actual operations
- Value as a credit against the congestion charge between two locations
- Value can reverse (becomes a charge) if structured as an Obligation
- Can be structured as an Option
- Supports the ability for Auctions (easily tradable)
- Simultaneous Feasibility still assessed but much further in advance of operating day

Reviewed Other RTOs

- Midwest ISO
- PJM
- ISO New England
- New York ISO
- California ISO (future market design)
- ERCOT Nodal Market
Basic Identical Traits

All 6 transmission congestion hedging models...

- are financial rights models *independent* of physical transactions
- conduct Annual and Monthly Auctions of transmission hedges
- allow non-utility entities to participate in the transmission hedge auctions and to hold transmission hedges
- have a secondary trading system to facilitate tracking ownership for “outside the auction” trades of transmission hedges.

Thoroughly Considered Transactional

- Requires use of Schedules to receive congestion credits
  - Similar to today, so not intimidating
- Drawbacks
  - NLS difficult to manage, especially during CAT cuts
  - Imbalance Offset method was developed to automatically create schedules, and remove those MW from the congestion calculations
    - Had its own problems
Thoroughly Considered Transactional - 2

- Don’t know hedge until DA, then too late to react
- Tried a hybrid method with some portion monthly commitments, and some DA
  - Unwieldy and ran into problems of competing priorities - Which firm is firmer in SFT analysis?
- The level of complexity, competing priorities in different timeframes and transparency issues ultimately ruled out the imbalance offset and the hybrid approach

Evaluations of Transactional and Independent Mechanisms

- A financial hedge gives participants the ability to handle many of these concerns within the market system

- Transmission Service is still required to be purchased per the requirements of the Tariff for NITS and PtP service.

- That service will be the basis for determining an initial allocation of the financial rights
Developed Consensus

- Could make either work
- Some stated a preference for Transactional (physical)
  - That is the business we are in
- Most stated that their choice was not overwhelming in either direction, but preferred Independent (financial)

Primary Reasons Given for Independent

- In the end, the majority were in favor of the independent financial transmission hedge mechanism as providing more flexibility for trading and reconfiguring the hedges, removing the requirement to manage Native Load Schedules and better supporting the establishment and use of trading hubs within SPP
**A Word About the Acronym “FTR”**

- The term “Financial Transmission Rights” is misleading at best
- FTR (as CHTF has used it) conveys NO RIGHTS AT ALL to transmission service
  - Transmission service will be acquired as in the past
- An FTR on a path is NOT a right to move power over the path.
- An FTR is a right to the receive the congestion cost on a path
- Perhaps we should use another term, like Transmission Congestion Right

---

**Scenario C - Repeated**

DA, WITH congestion, Gen C is Limited

*LMPs are assumed for illustration purposes*

<table>
<thead>
<tr>
<th>LMP= $70</th>
<th>500 MW $70 / MWh</th>
<th>g E</th>
<th>100</th>
</tr>
</thead>
<tbody>
<tr>
<td>LMP= $20</td>
<td>500 MW $20 / MWh</td>
<td>g C</td>
<td>400</td>
</tr>
</tbody>
</table>

Load=500 MW

LMP = $70  
**Pays LMP**

With Congestion → LMP varies by location

- $ paid at load = 500 x $70 = $35,000
- $ received at gen E = 100 x $70 = $7,000
- $ received at gen C = 400 x $20 = $8,000

Net market transaction is to PAY (35 - 8 – 7) = $20,000

Cost to serve load is own fuel cost PLUS $20,000 in Congestion Cost.

A hedge is needed.
Scenario C

DA, WITH congestion, Gen C is Limited

**Use TCR-like Hedge**

- LMP= $70
- 200 MW, $70 / MWh
- gE
- Paid LMP
- 100
- Load=500 MW
- LMP = $70
- gC
- 500 MW
- $20 / MWh
- 400
- Pays LMP

No change in energy charges

- $ paid at load = 500 x $70 = $35,000
- $ received at gen E = 100 x $70 = $7,000
- $ received at gen C = 400 x $20 = $8,000, netting to a cost of $20,000

TCR (E to Load) revenue = ($70 - $70) X 100 = zero

TCR (C to Load) revenue = ($70 - $20) X 400 = $20,000

The Net market transaction is ZERO

**Cost to serve load is own fuel cost**

Simultaneous Feasibility is Required for Revenue Neutrality

- TCRs must be aligned with the physical capability of the system
- Failure will result in a mismatch between the amount of congestion charges collected and paid back, leaving SPP either long or short
- SPP must remain revenue neutral
- Any mismatch is eliminated through uplift
**Scenario C**

What if TCR (C to load) had been for 500 MW?

LMP = $70

500 MW $70 / MWh

$ paid at load = 500 x $70 = $35,000

$ received at gen E = 100 x $70 = $7,000

$ received at gen C = 400 x $20 = $8,000, netting to a cost of $20,000

TCR (E to Load) revenue = ($70 - $70) X 100 = zero

TCR (C to Load) revenue = ($70 - $20) X 500 = $25,000

The Net market transaction is $5,000 paid by SPP to MP

**Without Sim Feas, SPP is now short $5,000, and must collect that amount through uplift**

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**Potential Cost Obligation**

One of the primary concerns with TCRs is the possibility of cost obligation.

- Because the proposed TCRs are of an obligation type, when congestion costs reverse, the holder is obligated to pay that difference.
- In the next example, the load is now served by the higher cost resource of the Load MP but congestion is reversed
- The TCR increases the overall cost to serve above and beyond the marginal cost at the Load.
**Scenario CH w/Outage – Cost Obligation**

DA, With Congestion reversed, Gen C unavailable, gen F and gen E are deployed. TCR from gen C to load. Gen F not owned by Load

- LMP = $80
- Gen C 500 MW Unavailable
- Gen F 500 MW
- Load = 500 MW

- $ paid at load = 500 x $80 = $40,000
- $ received at gen E = 500 x $80 = $40,000
- $ received at gen C = 0 x $100 = $0
- TCR C-Load now = 400 x -$20 = -$8,000
- **Net market Settlement for Load (40 – 40 + 8) = $8,000**
- **Cost to serve load is fuel cost of E plus counterflow obligation.**
- **TCR is now a cost obligation with unit out and congestion reversed.**

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**Risk is Different, But Not New**

- Today we all deal with the possibility of loosing a critical resource during peak times
  - May not be able to find replacement power
  - May not be able to get transmission service
  - Price exposure may be significant!
- But, utilities have always had to deal with these issues
- We are familiar with these risks
- We are unfamiliar with the financial hedge risks
Region’s Recent History of Concerns

- Fear of being forced into FERC’s Standard Market Design
- Concerns that LSE would lose the guarantee of using own resources to serve load, and be forced to buy from the market
  - Remember California?
- Retail Access initiatives
- Misunderstanding of confusing terms

Responding to the Concerns - Who Plays?

- One of the design elements the CHTF is recommending is that the initial allocation of hedge rights is based on existing firm transmission reservations
  - Only parties that can own firm transmission rights will be allocated financial rights
  - ONLY rights that the holder CHOSES to not accept and convert to TCRs will be available in an auction
What is the Goal?

- The goal is to create a hedge against transmission congestion that allows the MP to offer resources into the centralized commitment and DA market with a reasonable assurance that they will derive a benefit.
- Creating a deep, liquid TCR market is not the goal.

Develop Independent Hedge Design

- CHTF recognizes that the RSC has authority over the allocation of, and any transition mechanism to, financial transmission congestion hedging rights
- Last several weeks of CHTF activity were devoted to developing as much detail as possible on TCR design
Summary

- CHTF believes the Day 2 markets will be cost-beneficial
- The comparative analysis of transactional versus TCRs shows both can be made to work. TCRs get the nod because…
  - More flexibility for trading and reconfiguring
  - Removes the requirement to manage Native Load Schedules
  - Better supporting the establishment and use of trading hubs
- Allocation should be restricted to holders of firm transmission rights

References

- CHTF Report describes the details of design that CHTF suggests get adopted, and provides a thorough description of the CHTF decision process
- Generally, there are numerous FTR papers available publicly on most RTO websites. See the CHTF meeting minutes and material for references, links and examples reviewed
Questions?
Wind Integration Task Force (WITF) Update
July 2009
Wind Integration Task Force

The SPP WITF was developed by MOPC to determine the impact of integrating wind generation into the SPP transmission system and energy markets.

WITF Timeline Update

- Jan 14  MOPC Approval to complete RFP
- Feb 6    WITF Meeting to finalize RFP and Vendors
- Feb 15   RFP Submitted to Vendors
- Mar 16   RFP Responses due from Vendors
- Mar 25   WITF Meeting to select Vendor short-list
- Apr 8    WITF Meeting – Vendor presentations
- Apr 13   WITF Meeting – Final Vendor selection
- Apr 14   MOPC Update – Approval for study
- May 5    WITF Study Kickoff Meeting with CRA International
- June 30  WITF Status Update Meeting
- July 31  WITF Status Update Meeting
- August 25 WITF Status Update Meeting
- Dec 1    Vendor study complete
- Jan 2010 MOPC Presentation of Wind Integration Study
Wind Integration Task Force Study Scope

- Study scope definition
  - Base Case models
    1. 2010 models published in 2008 STEP
    2. CAWG/CBTF/MWG assumptions
  - Change Case definition
    1. 10% wind penetration with existing system
    2. 20% wind penetration with existing system
- Wind Profiles
  1. NREL wind data profiles from 2004-2006

Original Study Issues

- Issues
  - Data requirement issues
    1. 10 minute load data
    2. Flowgate data
    3. 2010 hourly load data
    4. Others
  - Modeling issues
    1. 10% case power flows
    2. 20% case power flows
    3. Dynamic models
    4. Others
Mitigation Plans

- On-site visits to SPP by CRA to assist in issue resolution
  - June 22 (3 days)
  - June 30 (1 day)
  - Additional visits being planned, as needed/required
- Study scope revision reasons
  - It proved to be more difficult to solve at 10-20% than expected
    1. Required 345kV and some 765kV upgrades to solve 20% models – this was unexpected
  - Too many unknowns in 30%-40% models
    1. Decided to forgo 30-40% studies for now
Study Schedule - Milestones

Task 1: Analysis Formulation
Task 2: Power Flow
Task 3: Reserve Req.
Task 4: Unit CMT
Task 5: Economic DSP
Task 6: Forecast Errors
Task 7: Best Practices
Task 8: Policy Changes
Task 9: Final Report

Study Schedule – Work Plan
Summary

- Revised study scope
  - Still meets study objectives
  - Still meets timeline objective
  - Allows greater focus on 10-20% cases

Questions?
ORDER

In Order No. 1 opening the inquiry in this docket, issued on October 7, 2008, the Arkansas Public Service Commission ("Commission") defined Sustainable Energy Resources ("SER") as including Demand Response ("DR"). Ten days later, on October 17, 2008, the Federal Energy Regulatory Commission ("FERC") issued its Final Rule in Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, III FERC Stats. & Regs. Preambles ¶ 31,281 (2008), as amended 126 FERC ¶61,261 (2009). The Final Rule ("Order No. 719") (FERC Docket Nos. RM07-19 / AD07-7), which is now pending a FERC ruling on various petitions for rehearing, was issued to improve the operation of organized wholesale electric markets in the areas of demand response, long-term power contracting, market monitoring, and Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISO") responsiveness. This Commission understands that there is no date certain by which the FERC will rule on the rehearing requests.

Order No. 719 mandates that RTOs and ISOs, in consultation with stakeholders, submit a compliance filing to explain how existing FERC Tariff language and practices comply with the reforms adopted in Order No. 719 or to specify plans to attain compliance. (Id. at p. 8).

On April 28, 2009, the Southwest Power Pool, Inc. ("SPP") submitted a filing revising the RTO's Open Access Transmission Tariff ("Tariff" or "OATT") in order to
comply with the FERC's requirements established in Order No. 719. (Southwest Power Pool, Inc., Docket No. ER09-1050-000, Submission of Order No. 719 Compliance Filing Revising Tariff). The SPP notes that its filing was developed through its stakeholder process, which is described in some detail. The 44-page SPP filing is accompanied by two exhibits showing changes to the RTO's OATT in both clean and red-line form.

This Commission believes that several issues of public interest in our SER inquiry are raised by FERC's Order No. 719 and the SPP's compliance filing in Docket No. ER09-1050-000 and thus may warrant consideration and the opportunity for comment by parties to this docket.¹ This Commission directs the parties to file comments in this Docket within 30 days after the FERC rules on SPP's Compliance Filing in FERC Docket No. ER09-1050-000.

The issue of particular interest to the Commission is the FERC's requirement that all RTOs and ISOs accept bids from DR resources, on a basis comparable to any other resources, for ancillary services that are acquired in a competitive bidding process, if the demand resources: (1) are technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules at or below the market-clearing price, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate. (Order No. 719 at 49). The FERC also required RTOs and ISOs to amend their market rules as necessary to permit an Aggregator of Retail Customers ("ARC" – a new term apparently coined by FERC in its rulemaking docket) to bid demand response on behalf of retail customers directly into the RTO's or ISO's organized markets, "unless the laws or

¹ Copies of both documents can be downloaded from the FERC's eLibrary website at www.ferc.gov/docs-filing/elibrary.asp.
regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.” (Id. at 154).

The Commission hereby notifies the parties to this docket that this issue is before the FERC. In the event that the FERC takes action on SPP's Compliance Filing in FERC Docket No. ER09-1050-000, this Commission may need to take appropriate action to determine the impact, if any, on its jurisdictional authority. Accordingly, the Commission orders and directs as follows:

1. The Commission directs the parties to file comments in this Docket within 30 days after the FERC rules on SPP's Compliance Filing in FERC Docket No. ER09-1050-000.

2. The Secretary of the Commission forthwith shall serve a copy of this order by electronic mail on counsel for all parties to this proceeding.

BY ORDER OF THE COMMISSION.

This 22nd day of May, 2009.

Paul Suskie, Chairman

Colette D. Honorable, Commissioner

Diana K. Wilson
Secretary of the Commission
ORDER

On April 6, 2009, the Arkansas Public Service Commission ("Commission") conducted a public hearing on the subject of the February 12, 2009, filing by the Southwest Power Pool, Inc. ("SPP"), acting as the Independent Coordinator of Transmission ("ICT") for the Entergy Services, Inc. ("Entergy") transmission system, in the above-styled Docket, of the ICT's Annual Performance Report for November 17, 2007 to November 17, 2008 (the "ICT's Annual Performance Report"). By Order No. 8 in this Docket the Commission directed the parties to submit post-hearing comments and respond to a set of questions propounded in the Order.

The Commission conducted the hearing on the ICT's Annual Performance Report and received additional comments to inform written comments that it intends to file with the Federal Energy Regulatory Commission ("FERC") in response to the Report, which was filed by the ICT with the FERC in Docket No. ER05-1065-000 on February 11, 2009. On April 24, 2009, written comments and responses to the
Commission's questions were filed by Entergy Arkansas Inc. ("EAI"); the Attorney General ("AG"), Arkansas Electric Cooperative Corporation ("AECC"); Southwest Electric Power Company ("SWEPCO"), Oklahoma Gas & Electric Company ("OG&E"), and Empire District Electric Company ("Empire District") (collectively the "Interested Parties"); Entegra Power Group LLC ("Entegra"), and Suez Energy Marketing, NA ("Suez"). The General Staff of the Commission ("Staff") filed a letter notifying the Commission that they did not intend to file comments.

Having considered the initial and post-hearing comments and the responses of the witnesses of the parties at the April 6th hearing, as well as Entergy's informational filing on the Weekly Procurement Process ("WPP") filed with the FERC on April 16, 2009, (and included as Attachment 1 to Order No. 8 in this Docket), the Commission makes the following findings.

**General Findings on the Status of the ICT Experiment and the WPP**

The Commission finds that the ICT experiment has to date failed to deliver significant benefits to EAI customers, owing largely to the extensive delays that were experienced in developing the software for and launching the WPP, thus depriving customers of the production cost savings associated with the vaunted third-party suppliers' displacement of more costly Entergy generation. What was expected to be the primary benefit of the ICT was only implemented on March 23, 2009, more than 28

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1 The Commission notes that the testimony at the non-adversarial public hearing on April 6, 2009 was provided by a representative of the Transmission Business Unit ("Entergy Transmission"), which refers to the organization that plans, constructs, and operates the Entergy Transmission System. The "Entergy Transmission System" refers to the collective transmission facilities owned by the Operating Companies and operated on behalf of the Operating Companies by the Transmission Business Unit. EAI as an Operating Company did not put forward any witnesses of its own during the proceeding. Because it is often difficult to distinguish between the decisions of EAI, the Entergy Operating Companies, and the operators of Entergy’s Transmission System this Order refers to EAI when referring to Entergy’s Arkansas operating Company and "Entergy" when referring to other Entergy entities.
months into the 48-month duration of the experiment approved by the FERC. It is far too soon to tell whether the WPP will succeed in producing sufficient benefits to justify the costs incurred to date in implementing the process -- $24.4 million according to Entergy's Informational Filing on the WPP. It is also noted that the WPP costs are only a part of the total costs of implementing the ICT, which according to Entergy's filings with the FERC cited by AECC have amounted to almost $100 million since 2006 ($69.5 million in 2006; $11.5 million in 2007; and $16.5 million in 2008). It is not clear to what extent the recently reported WPP costs are embedded in the total costs. And as noted by other parties, these are just Entergy's costs and do not include expenditures made by stakeholders and the state commissions participating in and monitoring the ICT's activities.

On the positive side, the Commission finds that the ICT has provided increased transparency on the Entergy System, enhanced transmission access, and helped to address transmission congestion. Based on the evidence in this Docket, however, the Commission is unable at this time to quantify these benefits and awaits with interest the assessment of the FERC later this year expressing its view of how the experiment has measured up to the metrics set forth by the FERC for judging its success. In the meantime, the Commission directs the ICT to file monthly reports on the results of the WPP including the costs and benefits of the experiment as it proceeds. If such reports are already being filed with the FERC pursuant to its order approving the start-up of the WPP, the Commission will accept such reports as compliant with this requirement.

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*Application in Entergy Services, Inc., FERC Docket No. ER07-93-000, dated October 30, 2006; Settlement Agreement filed on August 21, 2007, in Entergy Services, Inc., FERC Docket No. ER07-93-000; and Application of Entergy Services, Inc., FERC Docket No. ER08-1057, Section F.2.*
Transmission Planning and Entergy’s Use of “Note B”

The Commission notes that most of the parties agree that the ICT arrangement has brought some measure of transparency to the transmission planning process and improvements in the ICT’s day-to-day operational action on requests for transmission service for competitors of Entergy that use its Open Access Transmission Tariff (“OATT”). In particular, most agree that the planning processes administered by the ICT to develop both the Base Plan and the ICT Strategic Transmission Expansion Plan (“ISTEP”) are beginning to identify reliability and economic expansion projects beneficial to the Entergy transmission system. However, the Commission finds that the general consensus regarding improved transparency of the planning process for the Base Plan and ISTEP does not exist for Entergy’s process of developing the Construction Plan. In order to explain the lack of transparency in Entergy’s process of developing the Construction Plan, it is important to first summarize the differences between the Base Plan, the ISTEP, and the Construction Plan. In short, and as further explained below, the Base Plan addresses reliability concerns, the ISTEP identifies economic upgrades, and the Construction Plan represents Entergy Transmission’s determinations regarding what projects will be built during the next three years to meet both reliability and economic concerns. Stakeholders are invited to participate and submit comments in the development processes of each of the three plans but, as noted more fully below, the stakeholders and the ICT are not involved in the ultimate selection process used by Entergy and its Operating Companies in finalizing the Construction Plan. Therefore, this Commission finds the process used by Entergy to finalize the Construction Plan lacks both independence and transparency.
The Base Plan is developed by the ICT and represents the set of transmission upgrades that the ICT believes are required in order to meet Entergy Planning Criteria and the ICT's planning criteria enhancements. Base Plan projects are further described in Attachment T to Entergy's OATT as those needed to maintain reliable service to existing and future native load, to maintain existing firm transmission service reservations, and to maintain network integration of existing Network Resource Interconnection Service ("NRIS") and Network Integration Transmission Service ("NITS").

The ISTEP, under Attachment K to the Entergy OATT, is developed by the ICT to identify potential economic upgrades on the Entergy Transmission System. An economic upgrade is defined as accelerating an upgrade that is needed for reliability (i.e., an upgrade that is included in the Base Plan), modifying a Base Plan facility to relieve one or more economic constraints, or constructing a new facility or upgrade that is not included in the Base Plan. The ICT identifies such upgrades based on screening criteria that it develops and provides specified information about the potential benefits of the upgrades. It is important to note that the process outlined in Attachment K does not contemplate that any party will proceed directly with constructing upgrades identified by the ICT. Rather, § 14.6 of Attachment K provides that stakeholders will conduct their own economic analyses of the costs and benefits of the upgrades. In addition, Attachment K specifically provides that neither the ICT nor the Entergy System guarantees that any upgrade identified through the ICT study process will provide economic benefits to the funding customer or to any other party. To meet its obligation under Attachment K, in December 2007 the ICT issued its Phase I ISTEP
report, a high-level screening analysis of potential economic transmission upgrades across the entire Entergy Transmission System and on surrounding transmission systems. Entergy notes that this phase of the report was developed without analysis regarding the potential cost, construction timeline, or levels of production cost savings resulting from these transmission upgrade. (Initial Comments of EAI at 21). The ICT then sought stakeholder input on which of the projects identified in the Phase I ISTEP report should be the subject of a more detailed analysis. In April 2008, in response to stakeholder input, the ICT ranked the sets of upgrade projects. The top five projects, based on stakeholder input, were those indicated on page 16 of the Annual Report. After further study, the ICT concluded that three of the five projects showed potential economic benefits. These included (1) South Louisiana Bulk, (2) Central Arkansas 230 kV, and (3) Acadiana Area.

Entergy’s Construction Plan, developed after stakeholder comments between April 30, 2008 and March 3, 2009, and revised downward earlier this year to reflect reduced demand resulting from the current and on-going economic downturn, includes all transmission projects that Entergy expects to construct or initiate to construct over the 2009-2011 time period. It includes projects that Entergy believes are necessary to satisfy Entergy’s Planning Criteria as well as other economic upgrade projects identified by Entergy.

All of the active parties to this Docket, with the lone exception of EAI, agree that transparency is lacking with the selection process used by Entergy in developing the Construction Plan and in determining the ranking and subsequent benefit of reliability

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projects. It is not clear, for example, how the ISTEP projects become part of the Construction Plan as Base Plan projects that Entergy commits to build. Entergy responded to the comments of parties raising the transparency issue by pointing out that under Attachment K stakeholders are provided an opportunity to provide input, including written comments, regarding “data gathering and the study process” associated with development of the Construction Plan; “other inputs, assumptions, and methodologies relied on in developing the plan; the projects included in the plan; and why projects may not be included” (EAI Post-Hearing Comments at 20). This process, Entergy asserts, is both transparent and participatory. Entergy goes on to explain that under the OATT it is the Operating Companies that are the transmission provider, that are obligated to provide reliable service at a reasonable cost, and that are responsible for meeting the requirements to make comparable and non-discriminatory open-access transmission service available and for meeting all applicable NERC and SERC requirements. Entergy concludes that “the Operating Companies thus should decide what facilities are or are not included in the Construction Plan.” (EAI, Post-Hearing Comments at 25). Entergy consistently made clear at the Commission’s April 6, 2009 hearing as well as in its pre- and post-hearing filings that Entergy — and only Entergy — decides what facilities are built under the Construction Plan.

Finally, Entergy points out that the ICT must prepare a report identifying and explaining the differences between the ICT-developed Base Plan and the Entergy Transmission-developed Construction Plan.4 Entergy offers to conduct a technical

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4 Entergy and the ICT submitted such a report to the FERC on May 8, 2009, and the ICT filed the report with the Commission on May 11, 2009. See Differences Report Between ICT Base Plan and Entergy Construction Plan, Entergy Services, Inc., Docket No. ER05-1065-000. This report is discussed more fully below.
conference to address transmission planning issues and questions, including issues and questions related to the development of the Base Plan and the Construction Plan. (Id. at 26). The Commission accepts Entergy’s proposal to conduct such a technical conference, under conditions specified in more detail below.

What is missing in the above picture, the Commission finds, is a direct response by Entergy to the request of the parties for insight into the selection process used by the Operating Companies. If the Operating Companies are “the decider,” it is reasonable to ask how they reach their decisions on what facilities will be included in the Construction Plan. Notwithstanding the improvements in transparency resulting from the ICT planning process, this lack of transparency in what the Operating Companies “decide” to build raises serious questions as to the independence of the Entergy Transmission System from influence by the Entergy System over what transmission is constructed in the Entergy footprint and why.

As the ICT expresses it, while the development of the draft Construction Plan shares some of the transparent elements of the ICT’s Base Plan development process, “there are elements that are less transparent.” (SPP, Post-hearing Comments at 3.) The ICT goes on to note that “...Entergy’s methodology for incorporating non-reliability considerations into its cost/benefit analysis and, in turn, its determinations regarding the specific projects included in the Construction Plan, are not publicly disclosed.” Similarly, according to the ICT, “there is no publication of the process by which Entergy determines how the differences between the Construction Plan and the Base Plan are incorporated into the Construction Plan.” (Ibid.) Thus, the ICT concludes, “the development of the Entergy Construction Plan is comparatively less transparent than
the process associated with the ICT’s Base Plan.” *(Ibid.)*

The ICT notes that it is an “understandable source of stakeholder frustration that determinations of what projects are ultimately included in Entergy’s Construction Plan are based on analyses which remain somewhat unclear.” *(Id. at 4).* Furthermore, according to the ICT, “Inclusion in Entergy’s Planning Criteria of the methodology for determining a project’s cost/benefit score, and how this score is used in making upgrade determinations, could temper some of this frustration.” *(Ibid.)*

The Commission agrees with the ICT observations regarding the lack of transparency in Entergy’s Construction Plan process. The Commission also agrees with the ICT’s comment that another planning feature that could potentially be improved through greater transparency involves the use of operating guides, and related assumptions, in the development of Entergy’s Construction Plan. As the ICT states, “Currently, little is understood about how these operating guides are factored into Entergy’s construction decisions because relevant support and information is not provided to stakeholders.” *(Ibid.)* The Commission also agrees with the ICT that while Entergy may have legitimate confidentiality concerns, “sharing of this information (even if on some redacted or coded basis) could improve stakeholder confidence in Entergy’s Construction Plan and permit a more informed evaluation of Entergy’s ultimate planning decisions.” *(Id. at 4-5).*

The Commission finds reasonable the assertion by Suez that any cost-benefit analysis (“CBA”) currently performed by Entergy to assist in determining the ranking and subsequent benefit of reliability projects in the Construction Plan should be coordinated by the ICT and could be performed by an independent contractor. *(Suez,
Post-hearing Comments at 3). Further, the Commission finds reasonable Suez’s recommended course of action:

...The inputs into the CBA and results from the CBA should be shared, at the completion of the Construction Planning Process with those state commissions whose states are a part of the Entergy footprint. There should be an opportunity for consideration and comment on the inputs into the CBA and results from the CBA with the final CBA being shared with regulators and stakeholders. The ICT, stakeholders and state regulators should be provided a clear understanding of the projects to be constructed and their benefits to consumers from a reliability and economic standpoint, as well as the basis for their final ranking.

(Ibid, emphasis in original).

The Commission is aware of no provisions in Attachment K or elsewhere in the OATT that would prohibit Entergy from implementing a process similar to that described above and, given our assent to Entergy’s offer to conduct a technical conference on the Construction Plan and the Base Plan, directs that this issue and others raised by the parties in this Docket regarding the two plans (and the differences between them, as identified by the ICT) be addressed in the conference, which we suggest be coordinated with Entergy’s annual Transmission Summit, now scheduled for August 11, 2009.

Finally, the Commission takes notice of the May 8, 2009, joint filing by Entergy and the ICT of the “SPP Report on the Differences Between the 2009 ICT Base Plan and the 2009-2011 Entergy Construction Plan,” as required by the FERC’s orders approving the establishment of the ICT and Entergy’s OATT. The 14-page report, a copy of which was filed in this Docket on May 14, 2009, provides details concerning Base Plan projects not included in the Construction Plan and Construction Plan projects not included in the Base Plan, as well as other information, and has tables providing Entergy’s
explanation of the differences for the inclusion or exclusion of specific projects. Of concern to the Commission is the fact that of the 20 Base Plan projects not included in the Construction Plan, 13 of them were rejected by Entergy owing to Entergy's apparent determination that Entergy is satisfying the North American Electric Reliability Corporation ("NERC") standards through the use of Note B of NERC Standards TPL-001 and TPL-002.\textsuperscript{5} The other 7 projects were rejected either because Entergy determined that redispatch will solve the overload (and that NERC standards permit system adjustments as mitigation) or that they had been added to the Base Plan due to the ICT's planning criteria enhancement (the invocation of "the 100 MW Rule," which, as noted below, Entergy does not observe).

In the Annual Report, the ICT raises the issue of differences between itself and Entergy with regard to the interpretation of Note B to NERC standards TPL-001 and TPL-002. (Annual Report at 11). While both Entergy and the ICT allow the interruption of firm load to maintain reliability, the ICT interpretation limits the interruption of firm load to 100 MW in the Base Plan. In short, the new "100 MW Rule" requires Entergy to identify a mitigation plan "apart from load shedding" for any N-1 contingency which results in a thermal or voltage violation, internal or external to the faulted element, in which the breaker-to-breaker contingency relieves the violation and in which the Consequential Load exceeds 100 MW on peak. AECC states that it is Entergy's interpretation that Note B and the FERC discussion of non-consequential load in Order 693 permits the interruption of all load between two breakers for reliability purposes.

\textsuperscript{5} Note B states: "(b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserve) electric power Transfers."
This, AECC notes with concern, not only includes the initial interruption but also the continuation of the interruption until the problem is corrected. AECC concludes by stressing the fact that it is Entergy's interpretation that controls actual construction and that its attachments show that Entergy plans on allowing "hundreds of megawatts of its own, as well as AECC's members' loads to be exposed to extended outages for single contingency events." (Initial Comments of AECC at 3-4).

The Commission anticipates that stakeholders will submit comments to the FERC on the Differences Report and Entergy's reliance on Note B, expressing their further views on the degree to which Entergy's explanations of its selection process for the Construction Plan provide additional transparency, or not. For now, the Commission observes that there is little that is new in the Differences Report from what was filed or testified to at the hearing in this Docket. Unless Entergy discloses its methodology and metrics for incorporating non-reliability considerations into the cost/benefit analysis underlying its project selection process, the Commission questions how much will be accomplished at the technical conference Entergy intends to conduct. In the meantime, the Commission invites recommendations from the parties on how the different interpretations of Note B might be resolved by the Commission. Finally, in order to provide openness to Entergy's development of a Construction Plan and Entergy's use of Note B in the development of the Construction Plan, the Commission also directs Entergy to provide the metric or metrics it uses in determining when to use Note B rather than to invest in the transmission facilities.

**Entergy and Possible Membership in the SPP RTO**

The Commission finds that there is strong support among the parties for
examining the costs and benefits of full SPP membership by Entergy versus continuation of the ICT services agreement. An intriguing aspect of the SPP membership option is that EAI has given notice\(^6\) that it will exit the Entergy System Agreement on or before December 19, 2013.\(^7\) Therefore, whether Entergy as a whole or EAI as a stand-alone entity could join the SPP RTO is unclear. Consequently, what happens with Entergy's transmission planning at the end of EAI's exit from the System Agreement is a question that must be given careful consideration in the context of the FERC's pending consideration of EAI's February 2, 2009 request (joined in by Entergy Mississippi, Inc., now under consideration in FERC Docket No. ER09-636-000) that FERC clarify the terms under which the two companies can withdraw from the cost-sharing system that forces EAI's ratepayers to pay hundreds millions of dollars each year to the other operating companies.\(^8\)

The Commission adopts the suggestion made by the Interested Parties that SPP conduct, with the assistance of an independent third party, a comprehensive cost/benefit evaluation of the possibility of EAI's – as well as Entergy's – full SPP membership versus ICT services arrangements, as opposed to the status quo ante. Such a study would need to address technical barriers and other obstacles to Entergy's participation in SPP, such as:

\(^6\) Letter from EAI President and CEO Hugh McDonald to other Operating Company presidents and CEOs, dated December 19, 2005, giving required 96-month notice of withdrawal from the System Agreement, pursuant to Section 1.01 of the Agreement.

\(^7\) On November 7, 2007, Entergy Mississippi, Inc. (EMI) provided the same notice by letter of its intent to exit the system agreement effective on or before November 7, 2015.

\(^8\) The Commission notes that in the first two-years of EAI's bandwidth payments under the System Agreement Arkansas ratepayers have paid approximately $500 million to Entergy's other Operating Companies. This number is expected to approach a combined total of $900 million by the end of the third year of bandwidth payments.
- the difference in planning standards (e.g., Entergy’s broader interpretation of load-shedding mitigation strategies under Note B from NERC Reliability Standard TPL-002-0 vs. the 100 MW rule employed by the SPP as ICT);

- Entergy’s five-year transmission planning horizon vs. SPP’s ten-year horizon;

- the need for Entergy and its Operating Companies to accept the authority of the SPP Board to make construction decisions for new transmission;

- the different cost allocation methods used by Entergy and the SPP for new transmission lines;

- the costs and benefits to Entergy customers of moving to the energy imbalance market operated by the SPP and other markets under consideration by the RTO.

The Commission also directs the SPP to provide a report by July 1, 2009, comparing and contrasting the transmission planning horizon used by the SPP as RTO with that of Entergy. Likewise, the report should address the planning horizons used by other RTOs in the United States.

The Commission expects that in developing a Request For Proposal ("RFP") for the selection of an independent third-party consultant to conduct the cost benefit analysis the SPP would specify that at least two cases be examined: (a) the costs and benefits of membership in SPP by EAI as a stand-alone entity; and (b) the costs and benefits of full membership in SPP by the Entergy System as a whole. The Commission directs that the SPP report on or before July 1, 2009, on the progress in establishing a process for conducting such an analysis. The Commission directs the SPP to submit the results of the cost-benefit study by December 31, 2009. EAI is directed to assist the SPP in completing this study as requested by the SPP.

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9 The Commission is aware that the current 10 year planning horizon used by the SPP is expected to change to a much longer planning horizon.
Seams Agreement

There is general consensus among the parties and the ICT, and the Commission agrees, that Entergy should move with dispatch to negotiate and complete a comprehensive seams agreement with the SPP RTO, working with the stakeholders of both SPP and the ICT to develop such an agreement. The Commission believes that this process would be furthered by a FERC decision to require the development of such an agreement by a date certain, ideally prior to the end of the ICT's third year of operations in November 2009. The ICT opines in its Comments (SPP Post-Hearing Comments at 9) that if agreement can be reached on difficult cost allocation issues, it may be possible to finalize and implement a comprehensive seams agreement within six to nine months. The Commission agrees with observations of parties made in this Docket that the need for a seams agreement and the elimination or reduction of “rate-pancaking” would likely be obviated or significantly reduced by Entergy's full membership in the SPP RTO. In the meantime, however, the Commission urges the ICT and Entergy to redouble their efforts to reach a seams agreement and to update the recent analysis conducted for the ICT by CRA International, “Economic Impact of Eliminating Pancaked Transmission Rates between Entergy and SPP”, dated March 23, 2009, to account for recent changes in the financial and energy markets and the implications that the current economic crisis and proposed energy and environmental legislation and regulation may have for load and energy forecasts within the Entergy System.

The Commission also invites the SPP as an RTO, the ICT, and the parties to make recommendations concerning what needs to be included in a seams agreement and, in particular, for the SPP to develop and share a draft agreement addressing seams issues
for the consideration and comment of the parties. The Commission believes it would be helpful to hear from the SPP concerning seams agreements it already has with other entities and whether such agreements developed by other RTOs can be useful models for resolving issues between Entergy and SPP. The parties should file their recommendations and the information on existing seams agreements the SPP has currently executed should be filed by July 1, 2009.

**Cost Allocation and Attachment T**

As noted by the ICT, the cost allocation methods for transmission expansion within Entergy and SPP differ substantially. (SPP Post-Hearing Comments at 8). For reliability upgrades, as noted above, Entergy makes the ultimate determination, based upon Entergy's undisclosed cost-benefit analysis, whether a specific reliability project should be included in Entergy's Construction Plan, and Entergy is responsible for all costs of the included projects. In contrast, the SPP as an RTO has developed a cost allocation methodology to distribute the costs associated with reliability upgrades among its various members. This methodology is detailed in Attachment J of the SPP FERC Tariff and generally socializes one-third of the cost of any reliability upgrade among SPP members, while allocating the remaining two-thirds of the cost based on the megawatt-mile ("MW-mile") impact of the upgrade. The Commission interprets the SPP's comments as suggesting that some derivative of the SPP method "could promote more optimal planning and more closely align the benefits and costs of these upgrades" on the Entergy System.

Regarding economic projects, SPP has two approaches that are available. Recently the SPP developed a Balanced Portfolio methodology which optimizes the
transmission system with respect to economic generation within the region and provides that the cost allocation for such upgrades will be recovered by postage stamp rates across the RTO region. This is in addition to a mechanism that provides that a member of the RTO can voluntarily fund an upgrade and receive credits from future users of the facility. In contrast, the ICT notes, Entergy relies on the ICT's determination regarding whether a particular upgrade should be classified as a reliability upgrade (Base Plan) or an economic upgrade (Supplemental). All Supplemental upgrades under the Entergy cost allocation process (as provided for and approved by FERC in Attachment T to Entergy's OATT) are participant-funded with the requesting customer receiving both long-term and short-term financial payments for any future use of these projects. SPP states its belief that certain aspects of the SPP Balanced Portfolio process could be incorporated into the different long-term planning analyses conducted by the ICT and Entergy that consider economic projects.

The Commission agrees with the ICT that these fundamental differences regarding cost allocation for both reliability and economic upgrades present significant complications to the development of a comprehensive seams agreement and declares our intent to follow closely the analysis we would expect Entergy to make concerning the costs and benefits of a possible move towards planning standards similar to those used by SPP.

The Commission welcomes Entergy's offer to conduct a workshop to address questions relating to Attachment T, which we suggest might reasonably be held in conjunction with the upcoming Transmission Summit in August of this year. Accordingly, the Commission orders and directs as follows:
1. The Commission directs the ICT to file monthly reports on the results of the WPP including the costs and benefits of the experiment as it proceeds. If such reports are already being filed with the FERC pursuant to its order approving the start-up of the WPP, the Commission will accept such reports as compliant with this requirement.

2. The Commission accepts Entergy’s offer to conduct a technical conference on the Construction Plan and the Base Plan, and directs that this issue and others raised by the parties in this Docket regarding the two plans (and the differences between them, as identified by the ICT) and questions regarding Attachment T be addressed in the technical conference, which should be coordinated with Entergy’s annual Transmission Summit, now scheduled for August 11, 2009.

3. The Commission invites recommendations from the parties on how the different interpretations of Note B might be resolved and whether and how the Commission might advance the prospects of such resolution, including recommendations regarding possible Commission actions to resolve this difference. The Commission also directs Entergy to provide the metric or metrics it uses to determine when to use Note B than to invest in the transmission facilities. Such recommendations and comments shall be filed by noon on July 1, 2009.

4. The Commission directs the SPP to conduct, with the assistance of an independent third party, a comprehensive cost/benefit evaluation of full SPP membership by both EAI (as a stand alone entity) and Entergy versus the
existing ICT services arrangements, as opposed to the status quo ante. Such study shall address the technical barriers and other obstacles to Entergy’s participation in SPP as identified hereinabove. The Commission directs that the SPP report on or before July 1, 2009, on the progress in establishing a process for conducting such an analysis. The Commission directs the SPP to submit the results of the cost-benefit study by December 31, 2009. EAI is directed to assist the SPP in completing this study as requested by the SPP.

5. The Commission also directs the SPP to file a report by July 1, 2009, comparing and contrasting the transmission planning horizon used by the SPP as RTO with that of Entergy. Likewise, the report shall address the planning horizons used by other RTOs in the United States.

6. The Commission directs the ICT and Entergy to redouble their efforts to reach a seams agreement and to update the recent analysis conducted for the ICT by CRA International, “Economic Impact of Eliminating Pancaked Transmission Rates between Entergy and SPP”, dated March 23, 2009, to account for recent changes in the financial and energy markets and the implications that the current economic crisis and proposed energy and environmental legislation and regulation may have for load and energy forecasts within the Entergy System.

7. The Commission also directs the SPP as an RTO, the ICT, and the parties to make recommendations concerning what needs to be included in a seams agreement and, in particular, for the SPP to develop and share a draft agreement addressing seams issues for the consideration and comment of the
parties. The Commission believes it would be helpful to hear from the SPP concerning seams agreements it already has with other entities and whether such agreements developed by other RTOs can be useful models for resolving issues between Entergy and SPP. The parties should file their recommendations and the information on existing seams agreements the SPP has currently executed should be filed by July 1, 2009.

8. The Commission directs its General Counsel to cause an official copy of this Order to be filed in FERC Docket No. ER05-1065-000 as the official comments of the Commission on the ICT's Annual Performance Report.

9. The Secretary of the Commission forthwith shall serve by electronic mail a copy of this Order on counsel for all parties to this Docket.

BY ORDER OF THE COMMISSION,

This 29th day of May, 2009.

Paul Suskie, Chairman

Colette D. Honorable, Commissioner

Olan W. Reeves, Commissioner

Karen Shook (acting)
Diana K. Wilson,
Secretary of the Commission

I hereby certify that the following order notice of the Arkansas Public Service Commission has been served on all parties of record via U.S. mail with postage prepaid, using the address of each party as indicated in the official docket file.

Diana K. Wilson
Secretary of the Commission
Date: 05-29-2009
TEXAS
INFORMATION
SPP has requested feedback from this Commission regarding implementation of proposed tariff provisions in response to FERC Order No. 719. The tariff provisions require market participants who want to offer controllable load as a resource in the Energy Imbalance Service (EIS) Market on their own behalf or as an Aggregator of Retail Customers (ARC) to obtain a declaration that participation of their resources in the EIS Market is not precluded by the laws or regulations of the relevant electric retail regulatory authority.

By way of background, FERC Order No. 719 required RTOs and ISOs to address certain reforms in four areas: (1) demand response and scarcity pricing; (2) long-term power contracting; (3) market monitoring policies; and (4) RTO and ISO responsiveness. At issue in this memo is the requirement that all RTOs and ISOs accept bids from demand response resources on a basis comparable to any other resources for ancillary services that are acquired in a competitive bidding process, if the demand resources: (1) are technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules at or below the market-clearing price, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.

FERC also required amendment to RTO and ISO market rules to allow an ARC to bid demand response on behalf of retail customers directly into the organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit the customers aggregated in the bid to participate. FERC indicated that RTOs and ISOs should not be in the position of interpreting the laws or regulations of a relevant electric retail regulatory authority,

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2 The broad term “relevant electric retail regulatory authority” applies to a range of entities, including State Commissions, electric cooperative boards, and municipal authorities.
3 Order No. 719 at P 47.
4 Order No. 719 at P 154, 155.
5 Order No. 719 at P 49 n.78.
but the Order also does not require a retail regulatory authority to make any showing or take any action in compliance with the rule.\textsuperscript{6}

The SPP Board of Directors approved proposed revisions to Attachment AE of the SPP Tariff, which governs the EIS Market, and included the following subsection to Section 1.2.2 – Application and Asset Registration:

(i) A Market Participant wishing to offer controllable load as a resource in the EIS Market must include in its application and registration a certification by means of a declaration by the relevant electric retail regulatory authority, as applicable, that participation in the EIS Market by its controllable load resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Controllable load resources must meet all application, registration and technical requirements applicable to other resources offering imbalance energy in the EIS Market. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the EIS Market in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s). [emphasis added]

This provision generated a great deal of controversy, but the Board voted to approve the language and it is now pending at FERC.\textsuperscript{7} Proponents of requiring this “certification by means of a declaration” argue that without it, demand response resources and ARCs would be self-regulating their participation in the EIS Market and that it may place SPP in the untenable position of having to interpret state retail laws and regulations when it acts on a customer’s application to register its controllable load resources in the EIS Market. On the other hand, opponents of requiring this certification argue that it exceeds the intent of Order No. 719, that it places an additional requirement on demand response resources that do not apply to other resources, and that it enacts a barrier to participation by load. Opponents argue that Order No. 719 requires RTOs to treat demand response resources on a comparable basis to other resources in the RTO’s organized ancillary services markets, and requiring demand response resources to petition for a declaration does not provide comparable treatment with generation resources.

Although it is still uncertain whether FERC will accept SPP’s proposed language, SPP has requested the Regional State Committee (RSC) members to report back regarding implementation of this provision at the July 27, 2009 meeting. While I understand the positions of all the parties, this issue is difficult from a procedural standpoint. Clearly, it is a policy of the PUC to promote demand participation in markets, and P.U.C. SUBST. R. 25.507 specifically provides for Emergency Interruptible Load Service (EILS) in ERCOT. In fact, Loads Acting as a Resource are an essential part of the ERCOT market. Regarding aggregators, PURA §39.353

\textsuperscript{6} Order No. 719 at PP 53, 155.
\textsuperscript{7} Docket No. ER09-1050, Southwest Power Pool, Inc.
and P.U.C. SUBST. R. 25.111 pertain to aggregators for purposes of purchasing electricity, not for purposes of demand participation as a resource in the market. I think everyone would agree that neither PURA nor the PUC rules preclude controllable load from participating in the market in Texas. The question becomes how to make a “certification by means of a declaration.” I do not believe that a declaratory order would be appropriate since there may not be any controversy and advisory opinions are prohibited. Adopting a formal rule seems inappropriate because we would not be providing any guidance beyond a requirement that participation be in conformance with the relevant rules of the RTO or ISO. Therefore, to satisfy the SPP’s desire to not be held responsible for this legal determination, I propose that we delegate authority to the Executive Director to respond to any such request for certification by issuing a letter to the SPP stating that there are no PUC rules or PURA provisions that preclude controllable loads from participating in the EIS Market, provided that such participation is in conformance with the applicable RTO guidelines. The Executive Director would also have an ongoing responsibility to immediately notify SPP should there be any changes to PURA or PUC rules that would alter this determination. SPP has indicated that it would accept a “certification by means of a declaration” in this form.

The complicating factor comes from the attempt by various utilities to include interpretation of state-approved retail tariffs. As I understand the issue, some utilities are concerned over potential situations where a customer on an interruptible tariff may attempt to participate in the market, thereby receiving double benefit for essentially the same capacity and possibly not being available when called upon by either SPP or the utility. While I think situations like this could be remedied with proper market guidelines, I understand the desire to have the retail regulatory authority make the determination in the event there is disagreement between the market participant and the utility. Although some of those who promoted SPP’s proposed tariff language did not want the burden of seeking affirmative action to disqualify the resource’s participation, I do not see any way to address this matter except on a case-by-case basis given the volume of state-approved retail tariffs, the frequency by which those tariffs are amended, and the ability for customers to change the tariff under which they are receiving service without notice to the PUC. This makes it impractical, if not impossible, for a utility to shift its burden onto this Commission regarding ongoing interpretation of applicable tariff provisions. Therefore, I suggest that within the process of the letter certification by the Executive Director, the affected utility be given the opportunity to object to the specific load resource’s participation in the market under its current tariff. If the utility does not object, then the Executive Director issues the final letter certification noting that there was no objection by the utility. If the utility objects, then that specific fact situation can be addressed by the Commission. Just as the Commission’s Executive Director will have an ongoing responsibility to notify SPP should PURA or PUC rules change, the utility is on notice to continue to evaluate any future changes to the specific terms of the tariff applicable to the resource.

I believe this approach is the best alternative to meet three objectives: (1) satisfy SPP’s desire to not be in the position of having to make legal determinations, (2) not be overly burdensome on load such that market participation is discouraged contradictory to the intent of FERC Order No. 719, and (3) provide an adjudicatory forum in the event there is a real controversy but not require excessive action by the regulatory authority to comply with Order No. 719.

I look forward to discussing this matter at the open meeting.