Helping our members work together to keep the lights on... today and in the future
SPP: A Closer Look

Heather Starnes
Manager, Regulatory Policy
Our Beginning

• Founded 1941 with 11 members
  – Utilities pooled electricity to power Arkansas aluminum plant needed for critical defense

• Maintained after WWII to continue benefits of regional coordination
The SPP Difference

• Relationship - Based
• Member - Driven
• Independence Through Diversity
• Evolutionary vs. Revolutionary
• Reliability and Economics Inseparable
64 SPP Members

- Cooperatives: 14
- Municipals: 12
- State Agencies: 10
- Marketers: 7
- Investor-Owned: 6
- Independent Transmission Companies: 11
- Independent Power Producers / Wholesale Generation: 4
SPP at a Glance

- Located in Little Rock
- ~475 employees
- $139 million operating budget (2011)
- 24 x 7 operation
- Full redundancy and backup site
Members in 9 states

Arkansas
Kansas
Louisiana
Mississippi
Missouri
Nebraska
New Mexico
Oklahoma
Texas

Provide services to Entergy on contract basis (ICT)
Operating Region 2010

- 370,000 miles service territory
- 859 generating plants
- 6,101 substations
- 48,930 miles transmission:
  - 69 kV – 12,722 miles
  - 115 kV – 10,143 miles
  - 138 kV – 10,009 miles
  - 161 kV – 5,097 miles
  - 230 kV – 3,787 miles
  - 345 kV – 7,079 miles
  - 500 kV – 93 miles
Did You Know?

• SPP’s members serve over 15 million people

• In 2010, SPP members completed 78 transmission projects totaling $468 million.

• SPP’s transmission owners collect ~$800 million annually to recoup costs of transmission, and have over $4.7 billion in net transmission investment.

• 48,930 miles of transmission lines in SPP’s footprint would circle the earth - almost twice!
SPP Strategically

BUILD A ROBUST TRANSMISSION SYSTEM

DEVELOP MARKET EFFICIENT PROCESSES

CREATE MEMBER VALUE
Our Major Services

- Facilitation
- Reliability Coordination
- Transmission Service/Tariff Administration
- Market Operation
- Standards Setting
- Compliance Enforcement
- Transmission Planning
- Training

Regional
Independent
Cost-effective
Focus on reliability
Facilitation: Helping our members work together
Reliability Coordination

- Monitor grid 24 x 365
- Anticipate problems
- Take preemptive action
- Coordinate regional response
- Independent

As “air traffic controllers,” our operators comply with...

...over 1,300 pages of reliability standards and criteria
Transmission Service

- Provides “one-stop shopping” for use of regional transmission lines
- Consistent rates, terms, conditions for all users
- Independent
- Process ~9,200 transactions/month
- 2010 transmission service transactions = $698 million

As “Sales agents,” we administer ...
Compliance Enforcement and Standards Setting

• SPP Regional Entity enforces compliance with federal NERC reliability standards
• Creates regional reliability standards with stakeholder input
• Provides training and education to users, owners, and operators of bulk power grid
Training

• 2010 Training program awarded over 21,000 continuing education hours to 410 operators from 25 member companies

• SPP offers:
  – Regional/sub-regional restoration drills
  – System operations conferences
  – Regional emergency operations sessions
  – Train-the-Trainer classes
Transmission Planning: How does SPP decide what and where transmission is needed?

- **Generation Interconnection Studies**
  - Determines transmission upgrades needed to connect new generation to electric grid

- **Aggregate Transmission Service Studies**
  - Determines transmission upgrades needed to transmit energy from new generation to load
  - Shares costs of studies and new transmission

- **Specific transmission studies**

- **Integrated Transmission Planning process**
Integrated Transmission Planning: Economics and Reliability Analysis

- Annual Near-Term plan
- Reliability is primary focus
- Identifies potential problems and needed upgrades
- Coordinates with ITP10, ITP20, Aggregate and Generation Interconnection study processes

- Analyzes transmission system for 10-year horizon
- Establishes timing of ITP20 projects

- Develops 345 kV+ backbone for 20-year horizon
- Studies broad range of possible futures
SPP Transmission Expansion Plan

• Summary
  – Comprehensive summary of projects for 2011 – 2021 horizon
  – Approximately $5 billion in projects within the horizon
  – Report contains OATT Attachment O and seams agreement coordinated planning

• Highlights
  – 50 Notifications to Construct (NTC) issued to members for 2011
  – NTCs for Priority Projects issued in July 2010
# Planned Transmission – 3-Year Summary

<table>
<thead>
<tr>
<th>Upgrade Type</th>
<th>2010 STEP (Nearest 10 Million)</th>
<th>2009 STEP (Nearest 10 Million)</th>
<th>2008 STEP (Nearest 10 Million)</th>
<th>(Dollars in Millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010 Priority Projects</td>
<td>$1,420</td>
<td></td>
<td></td>
<td>$1,420</td>
</tr>
<tr>
<td>2009 Balanced Portfolio</td>
<td>$820</td>
<td>$770</td>
<td></td>
<td>$820</td>
</tr>
<tr>
<td>Transmission Service Request and Generation Interconnection Service Agreements</td>
<td>$650</td>
<td>$540</td>
<td>$320</td>
<td>$650</td>
</tr>
<tr>
<td>Reliability - Base Plan</td>
<td>$1,220</td>
<td>$1,690</td>
<td>$880</td>
<td>$1,220</td>
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<tr>
<td>Reliability - Other</td>
<td>$540</td>
<td>$1,030</td>
<td>$520</td>
<td>$540</td>
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<tr>
<td>Sponsored Upgrades</td>
<td>$320</td>
<td>$620</td>
<td></td>
<td>$320</td>
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<tr>
<td>SPP Subtotal</td>
<td>$4.65B</td>
<td>$4.35B</td>
<td>$2.3B</td>
<td>$4.65B</td>
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<tr>
<td>non-OATT upgrades</td>
<td>$420</td>
<td>$100</td>
<td>$350</td>
<td>$420</td>
</tr>
<tr>
<td>Appendix A - TOTAL</td>
<td>$5.1B</td>
<td>$4.45B</td>
<td>$2.7B</td>
<td>$5.1B</td>
</tr>
</tbody>
</table>

Has filed Service Agreement or is Board-approved
Regional State Committee

• Retail regulatory commissioners:
  Arkansas  Missouri  Oklahoma
  Kansas  Nebraska  Texas
  Mississippi  New Mexico
  Louisiana maintains active observer status

• Responsibilities/Authorities
  - Cost allocation
  - Ensure adequate supply
  - Market cost/benefit analyses
# RSC & CAWG

<table>
<thead>
<tr>
<th></th>
<th>Regional State Committee (RSC)</th>
<th>Cost Allocation Working Group (CAWG)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arkansas</td>
<td>Commissioner Reeves</td>
<td>Sam Loudenslager/Pat Mosier</td>
</tr>
<tr>
<td>Kansas</td>
<td>Commissioner Wright</td>
<td>Tom DeBaun/James Sanderson</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>Commissioner Murphy</td>
<td>Trent Campbell</td>
</tr>
<tr>
<td>Missouri</td>
<td>Commissioner Davis</td>
<td>Adam McKinnie</td>
</tr>
<tr>
<td>Nebraska</td>
<td>Chairman Siedschlag</td>
<td>John Krajewski</td>
</tr>
<tr>
<td>New Mexico</td>
<td>Commissioner Lyons</td>
<td>Craig Dunbar</td>
</tr>
<tr>
<td>Texas</td>
<td>Chairman Nelson</td>
<td>Richard Greffe</td>
</tr>
</tbody>
</table>
Who pays for transmission projects?

- **Sponsored**: Project owner builds and receives credit for use of transmission lines
- **Directly-assigned**: Project owner builds and is responsible for cost recovery
- **Highway/Byway**: Most SPP projects paid for under this methodology

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Region Pays</th>
<th>Local Zone Pays</th>
</tr>
</thead>
<tbody>
<tr>
<td>300 kV and above</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>above 100 kV and below 300 kV</td>
<td>33%</td>
<td>67%</td>
</tr>
<tr>
<td>100 kV and below</td>
<td>0%</td>
<td>100%</td>
</tr>
</tbody>
</table>
Integrated Marketplace

Why?
What is it?
Impacts to SPP Members

Richard Dillon
Director, Market Design
## Key Dates in Integrated Marketplace History

<table>
<thead>
<tr>
<th>Key Milestone</th>
<th>Completion Date</th>
</tr>
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<tbody>
<tr>
<td>Cost-Benefit Analysis for Future Markets Completed</td>
<td>April 2009</td>
</tr>
<tr>
<td>RSC Endorsement of Cost-Benefit Analysis</td>
<td>April 2009</td>
</tr>
<tr>
<td>Board Approval of Implementation Budget</td>
<td>April 2011</td>
</tr>
<tr>
<td>SPP Stakeholders developed detailed Market Design</td>
<td>2008-2010</td>
</tr>
<tr>
<td>MWG Finalized Baseline Protocols</td>
<td>September 2010</td>
</tr>
<tr>
<td>MOPC Approval of Baseline Protocols</td>
<td>October 2010</td>
</tr>
<tr>
<td>Board Approval of Implementation Budget</td>
<td>January 2011</td>
</tr>
<tr>
<td>SPP Contracted Vendors</td>
<td>May 2011</td>
</tr>
</tbody>
</table>
Marketplace Timeline

FAT: Factory Acceptance Test | SAT: Site Acceptance Test | FIT: Functional Integration Test | PT: Performance Test
Why Integrated Marketplace?

• Net Benefits ~ $100 million/year
• Reduce total energy costs through centralized unit commitment while maintaining reliable operations
• Day-Ahead Market allows additional price assurance capability prior to real-time
• Includes new markets for Operating Reserve to support implementation of Consolidated Balancing Authority (CBA) and facilitate reserve sharing
## EIS vs. Integrated Marketplace Features

<table>
<thead>
<tr>
<th>Capability</th>
<th>EIS</th>
<th>Integrated Marketplace</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Transmission</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Reservations</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>• Scheduling (internal/external)</td>
<td>All Reservations</td>
<td>Third Party Reservations</td>
</tr>
<tr>
<td>• Transmission Congestion Rights</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td><strong>Energy</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Bilaterals</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>• Day-Ahead Market</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>• Real-Time Balancing Market</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td><strong>Operating Reserves and Regulation</strong></td>
<td>Self-Designated</td>
<td>Market</td>
</tr>
<tr>
<td><strong>Unit Commitment</strong></td>
<td>Self-Commitment</td>
<td>Centralized Commitment</td>
</tr>
<tr>
<td><strong>Balancing Authority</strong></td>
<td>Multiple</td>
<td>Single</td>
</tr>
</tbody>
</table>
SPP design leverages proven features from other RTO markets

<table>
<thead>
<tr>
<th>Feature</th>
<th>CAISO</th>
<th>ERCOT Nodal</th>
<th>MISO</th>
<th>PJM</th>
<th>SPP Marketplace</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-Ahead Market</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
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<tr>
<td>Real-Time Market</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
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<tr>
<td>Marginal Losses</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
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<tr>
<td>Co-Optimization</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Must Offer in Day-Ahead Market</td>
<td>✓</td>
<td></td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Resource Make-Whole Payment</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Transmission Congestion Rights/Auction Revenue Rights (TCR/ARR)</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
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<tr>
<td>Virtual Energy</td>
<td>Feb 2011</td>
<td>✓</td>
<td>✓</td>
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<td>✓</td>
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</table>
Design was selective for regional differences

<table>
<thead>
<tr>
<th></th>
<th>CAISO</th>
<th>ERCOT Nodal</th>
<th>MISO</th>
<th>PJM</th>
<th>SPP Marketplace</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined-Cycle Special Handling</td>
<td>Partial Implementation</td>
<td>In Process</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>5-Minute Settlement</td>
<td></td>
<td></td>
<td>✓ (Operating Reserve only)</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Zonal Operating Reserve Cost Allocation</td>
<td></td>
<td></td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Installed Capacity Market</td>
<td>Reliability Must Run</td>
<td></td>
<td></td>
<td>✓</td>
<td></td>
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</tbody>
</table>
SPP Integrated Marketplace Functions

Time

ARR/TCR Auction → Day Ahead Market → Day Ahead Reliability Unit Commitment → Intra-Day RUC Real-Time Balancing Market → Settlement

- Performs unit commitment
- Sets DA prices
- TCRs cleared

Makes sure enough capacity committed for next operating time frame

Real-Time dispatch much like today’s EIS Market
Day-Ahead Market Scope and Objective

• Determines least-cost solution to meet Energy Bids and Reserve requirements

• Participants submit Offers and Bids to purchase and/or sell Energy and Operating Reserve:
  – Energy
  – Regulation-Up
  – Regulation-Down
  – Spinning Reserve
  – Supplemental Reserve
Day Ahead market makes regional generation choices

SPP’s Day Ahead market selects the most cost-effective and reliable mix of generation for the region.
Benefits of Operating Reserves market

- Greater access to reserve electricity
- Improve regional balancing of supply and demand
- Facilitate integration of renewable resources

If the wind gusts and turbines trip, another type of reserve generation, such as gas, needs to immediately replace that supply. The Operating Reserves market offers reserve energy for sale.
Day-Ahead Market to achieve cost-effective unit commitment

- “Must offer” for physical Resources proposed in market design
- Includes Offers/Bids for virtual supply and virtual Load
- Import/Export schedules may also be submitted
- Co-optimizes Energy and Operating Reserve and produces Locational Marginal Prices (LMPs) and Market Clearing Prices (MCPs) to meet Energy Bids and Operating Reserve
Day-Ahead Market creates financially binding energy and commitment forecast

- Preliminary Unit Commitment is performed
- Creates financially-binding day-ahead schedule for Energy and Operating Reserve for Resources and Load that participate
- SPP guarantees revenue sufficiency of committed Resource Offers
- Transmission Congestions Rights are settled with these LMPs
Reliability Unit Commitment (RUC) Scope and Objective

• Day-Ahead RUC performed following Day-Ahead Market clearing

• Intra-Day RUC performed throughout Operating Day as needed, at least every four hours

• RUC ensures market physical commitment and produces adequate deliverable capacity to meet SPP Load Forecast and Operating Reserve requirements
RUC is in addition to Day-Ahead Market

- Every available Resource has to offer
- SPP guarantees revenue sufficiency of committed Resource Offers
Real-Time Balancing Market similar to today’s EIS - balancing Resources and Load.

- Uses Security Constrained Economic Dispatch (SCED) to ensure results are physically feasible
- Operates on continuous 5-minute basis
  - Calculates Dispatch Instructions for Energy and clears Operating Reserve by Resource
- Energy and Operating Reserve are co-optimized
- Settlements based on difference between results of RTBM process and Day-Ahead Market clearing
- Charges imposed on Market Participants for failure to deploy Energy and Operating Reserve as instructed
EIS Market BAs

SPP EIS BAs (16)

Not in EIS Market SPP is TSP (1)

1st tier BAs

---

Balancing Authority boundaries were developed by SPP Technical Studies and Modeling personnel on the basis of transmission ownership within the SPP footprint and are approximate representations only.
Auction Revenue Rights (ARRs) and Transmission Congestions Rights (TCRs)
ARRs and TCRs allow Resource owners to be indifferent to unit commitment impact on congestion
Auction Revenue Right (ARRs) ...

- Market Participant’s entitlement to a share of revenue generated in TCR auctions

- Allocated to Market Participants based on firm transmission rights (NITS or PTP) on SPP transmission grid

- Can be a credit or charge based on the TCR auction clearing price of the ARR path
Transmission Congestion Rights (TCRs) are...

• Financial Instruments that entitle owner to a stream of revenues or charges

• Based on hourly Day Ahead marginal congestion component differences across the path
ARRs awarded annually – are basis of TCRs

- ARRs allocated annually (in April)
- Market Participants nominate from Firm Transmission Service
  - Network Integrated Transmission Service agreement
  - Point to Point Firm Transmission Service Request

- ARRs awarded
  - Monthly
  - Seasonal
  - On Peak
  - Off Peak
How can I obtain TCRs?

• Annual TCR auction
  – Holder converts ARR
  – Purchase transmission capability

• Monthly TCR auction
  – Purchase “left over” transmission capability

• Short-Term TCR request
  – Request with Transmission Service Request

• TCR secondary market
TCRs Process Overview

TCs identify and confirm NITS and Firm PTP

Verification

TCs Nominate Annual ARR Awards

Annual ARR Awards

Annual TCR Auction

TCs Nominate Incremental ARR Awards

MPs Submit Bids to Buy TCRs

MPs

Receive Annual and Monthly Auction Revenue

TCR Market Settlements

Cleared Bids Pay Cleared Offers are Paid

DA Market Settlements

Incremental ARR Award MW

Receive Monthly Auction Revenue

DA Market Settlements

Incremental ARR Award MW

Receive Monthly Auction Revenue
Settlement of ARRs/TCRs

- Net Auction revenues are allocated to holders of ARRs
- Daily TCR settlements use Day-Ahead Market prices
- Auction Revenues, congestion revenues, and congestion rights revenues are settled concurrently with the Operating Day.
Impact on SPP Members
New Member Activities: TCR Markets

• Staffing to support **mock TCR Markets**, starting by 2Q 2012

• Staffing to support ARR processes and TCR auctions
  – Monthly/Seasonal ARR process & TCR auction (42 annual model inputs)
  – Monthly TCR auction (2 or 4 monthly model inputs)

• Staffing to support Secondary Market
  – Bulletin board system
  – Bilateral trading of existing TCRs
New Member Activities: Operations

• Staffing to support Day Ahead and Real-Time Balancing Market

• Develop Day-Ahead and Real-Time Decisional Data, including:
  – Three-Part Offers (Energy, Start Up, No Load)
  – Operating Reserve Offers (4 products)

• Work with vendors to develop software for internal use
  – Lead time is at least one year prior to delivery to MPs
  – SPP plans to meet with at least OATI, PCI, and ABB in February to review protocols and persuade development to begin
**New Member Activities: Settlements**

- Receive increased settlement statement detail
  - 47 charge types vs. 7 currently and over 120 billing determinants
- Understand complex calculations involving market-wide totals or rates
  - Make Whole Payments, Marginal Loss Surplus
- Analyze Transmission Congestion Settlements
- Develop new system interactions
- Review processes for credit
  - Impacts of TCRs & ARRs
- Enhance reporting – internally and externally
Summary

- Although Integrated Marketplace implementation is March 2014, Market Participants need to prepare sooner:
  - Analyze internal staffing
  - Develop software products
  - Develop Offers and Bids
Integrated Marketplace: Regulatory Timeline

<table>
<thead>
<tr>
<th>Year</th>
<th>Quarter</th>
<th>Design (6/1 – 9/30)</th>
<th>Build (10/1 – 6/30)</th>
<th>FAT (7/1 – 9/30)</th>
<th>SAT (10/1 – 12/31)</th>
<th>Market Trials (1/13 – 1/14)</th>
<th>Cutover &amp; Deploy (1/1 – 3/31)</th>
</tr>
</thead>
</table>

### Program Timeline

#### State Commissions
- Approval letters from State Commissions (10/1)
- State commission approvals (3/1)

#### SPP
- RTWG approval of Tariff revisions (11/18)
- MOPC reviews/approves Tariff revisions (12/6)
- Board approves Tariff revisions (1/31)
- File readiness/reversion plans (3/1)
- Potential compliance filing (8/13)

#### FERC
- Conditional Order (6/29)
- Final conditional approval (12/31)
- File readiness cert. (1/2)
- Final go-live order (1/31)

#### NERC
- NERC approves CBA cert. (12/4)
Market Participant Milestones

- **May 2, 2011**: SPP begins Marketplace software builds
- **April 2, 2011**: Participants develop market software/ensure staffing adequate and trained
- **May 16, 2011**: Participants ready to begin TCR mock auctions
- **June 1, 2011**: Participants make appropriate regulatory filings
- **January 1, 2012**: Participants finalize registration data necessary to participate in Marketplace
- **January 1, 2013**: Participants’ market systems ready for interface testing with SPP

**MAY 15, 2013**

**PARTICIPANTS READY FOR SYSTEM INTEGRATION**

**TCR Market Trials Begins**