Southwest Power Pool
BOARD OF DIRECTORS MEETING

Tuesday, February 20, 2001

Hyatt Hotel – Dallas/Ft. Worth Airport
Skyline A Room – West Tower

- A G E N D A -

11 a.m. – Call to Order

1. Administrative Items ....Gary Voigt
    a. Approval of Minutes

2. Secretary's Report...Nick Brown
    a. RTO Filing
    b. Results of Email Vote
    c. Penalty Payout
    d. Financing of Market Settlement Cost

3. Industry Issues Report... John Marschewski
    a. Federal Energy Regulatory Commission
    b. Midwest ISO Withdrawals
    c. California Retail Market
    d. State Retail Schedule
    e. Federal Energy Legislation

4. Commercial Practices Committee Report...Trudy Harper
    a. Regional Tariff Working Group
    b. Market Settlement Working Group
    c. Congestion Management Systems Working Group

5. Engineering & Operating Committee Report ....Mel Perkins

6. NERC Board of Trustees Report ....Tom Grennan

7. Operations Report ....Carl Monroe

8. Ice Storm Damage Report...Richard Verret

9. State Regulator Comments ....

3 p.m. – Adjournment

Southwest Power Pool
BOARD OF DIRECTORS MEETING
Hyatt Regency - Wichita, Kansas
November 6, 2000

- Summary of Action Items -

1. Approved minutes of the August 30, 2000 Board of Directors meeting as distributed.

2. Approved recommended actions by the Commercial Practices Committee to change the name of the Market Rules Working Group to Congestion Management System Working Group and to approve its scope statement.

3. Approved recommended changes by the Engineering & Operating Committee to SPP Criteria 5, Section 5.1 (and the addition of Appendix 7) and changes to Section 5.2 to become effective after SPP recognition as an RTO and execution of new membership agreements.

4. Approved a recommendation from the Employee Benefits Working Group to make a 3.2% salary structure adjustment and a 5.0 percent merit increase for 2001.

5. Approved the Finance Working Group recommendations for the 2001 SPP administrative budget of $19,935,550 and associated long-term financing of the market settlement systems at a fixed interest rate.

MINUTES NO. 73

Southwest Power Pool
BOARD OF DIRECTORS MEETING
Hyatt Regency - Wichita, Kansas
November 6, 2000

<u>Agenda Item 1 - Administrative Items</u>
SPP Chair Mr. Gary Voigt called the meeting to order at 1:07 p.m. and called for a round of introductions. The following directors were in attendance or represented by proxy:

Mr. David Christiano, City Utilities of Springfield, MO;
Mr. Harry Dawson, OK Municipal Power Authority;
Mr. Jim Eckelberger; non-stakeholder director;
Mr. Greg Geisler, proxy for Ms. Trudy Harper, Tenaska Power Services Company; and for Ms. Lydia Vollmer, PECO Power Team;
Mr. Tom Grennan, Western Resources;
Mr. Quentin Jackson, non-stakeholder director;
Mr. Stephen Parr, KS Electric Power Cooperative;
Mr. Tom McDaniel, non-stakeholder director;
Mr. Gene Reeves, proxy for Mr. Michael Deihl, Southwestern Power Admin.;
Mr. J. M. Shafer, Western Farmers Electric Cooperative;
Mr. Harry Skilton non-stakeholder director;
Mr. Mark Stegall, proxy for Ms. Kim Casey, Dynegy Marketing & Trade;
Mr. Al Strecker, OG+E;
Mr. Larry Sur; non-stakeholder director;
Mr. Richard Verret, American Electric Power;
Mr. Gary Voigt, Chair, Arkansas Electric Cooperative Corp.; and
Mr. John Marschewski, Southwest Power Pool, Inc.

There were 34 persons in attendance representing 18 members, 16 guests and 1 regulatory agency (Attendance List – Attachment 1). The Secretary received 3 proxy statements (Proxy – Attachment 2). Mr. Voigt referred to a full agenda (Agenda – Attachment 3) and asked for necessary modifications to draft minutes of the August 30, 2000 meeting (Minutes – Attachment 4) or a motion for approval. Mr. McDaniel moved that the minutes be approved as distributed. Mr. Verret seconded this motion, which passed unopposed. Mr. Voigt submitted a schedule of future meetings (Meeting Schedule – Attachment 5). This schedule includes additional meetings moving to a quarterly schedule. Mr. Jackson moved to accept this schedule with a change matching a day and date. Mr. Verret seconded this motion and the 2001 and 2002 schedule of meetings was approved without opposition.

<u>Agenda Item 2 – Commercial Practices Committee Recommendations</u>
Mr. Voigt asked Mr. Greg Geisler to present a report on behalf of Commercial Practices Committee Chair Trudy Harper. Mr. Geisler presented recommended actions from the Commercial Practices Committee for Board of Directors approval to change the name

of the Market Rules Working Group to Congestion Management System Working Group better representing the group's scope of responsibilities and also to approve their formal statement of scope (CMSWG Charter – Attachment 6). Mr. Reeves moved to approve this recommendation. This motion was seconded by Mr. Strecker and was approved unanimously.

Agenda Item 3 – Engineering & Operating Committee Recommendations
Mr. Mel Perkins, Chair of Engineering & Operating Committee (EOC), was asked to report on activities of his committee. Mr. Perkins reported EOC recommended changes to SPP Criteria 5 (Criteria 5, Section 5.1 changes – Attachment 7). The original SPP Criteria 5 specified that the data would be exchanged at least every ten minutes. Appendix 7 specifies that the periodic ICCP data be exchanged no less frequently than every thirty seconds. Status point data will continue to be exchanged on a by-exception basis whenever possible, with a ten-minute integrity report. Mr. Strecker motioned approval of the recommended changes. Mr. Eckelberger seconded this motion, which passed without opposition.

Mr. Perkins then referred to recommended changes in SPP Criteria Section 5.2 requiring SPP approval of transmission maintenance schedules and informed the Board of Directors that these changes would be in conflict with the current SPP Membership Agreement if changed before RTO status is achieved. Mr. Perkins stated the current membership agreement only requires coordination with SPP. Mr. Brown suggested approving this recommendation with an effective date after the RTO filing with the new Membership Agreement is approved by FERC and executed by the membership. Jim Eckelberger pointed out that the 30 seconds change had not been made in Section 5.2.4.1. Mr. Harry Dawson moved to make the recommended changes with the date stipulation suggested by Mr. Brown. Mr. Verret seconded the motion, which passed unopposed.

Agenda Item 5 – Finance Working Group Recommendations
Mr. Voigt skipped to Agenda Item 5 calling on Mr. Tom Grennan, Chair of the Finance Working Group for a report. Mr. Grennan stated the Finance Working Group consists of himself, Mr. Gene Argo, Ms. Trudy Harper and SPP President Mr. John Marschewski. Mr. Grennan presented the proposed draft of the SPP administrative budget for 2001 (2001 Administrative Budget – Attachment 8). He stated there was approximately a $7,200,000 increase over 2000 due to supporting the RTO filing and market settlement responsibilities. Mr. Grennan complimented Mr. Marschewski and the SPP staff for accomplishing what was asked of them and working diligently to achieve RTO recognition. He also stated that additional staff is needed making the total staff reach 119 by the end of 2001. After discussion, Mr. Grennan moved and Mr. Voigt seconded the Board of Directors approve the recommended budget for 2001 as presented. This decision was deferred until Mr. J.M. Shafer could present the

Employee Benefits Working Group recommendation.

Agenda Item 4 – Employee Benefits Working Group Recommendations

Mr. Voigt then asked Mr. J.M. Shafer, Chair of Employee Benefits Working Group (EBWG), for an update on the activities of this group. Mr. Shafer stated the group had contracted with Hewitt Associates in 1999 to conduct a market analysis survey of staff positions and by contacting the peers and some members of SPP (Budget Projections – Attachment 9). Hewitt proposed adjusting the SPP salary structure 3.2% to keep salary midpoints current to the marketplace. The EBWG agreed with Hewitt's conclusions. Mr. Shafer presented the EBWG recommendation of a 3.2% salary structure adjustment and a 5.0% merit increase for 2001 as a motion. Mr. Dawson seconded this motion, which passed without opposition.

Mr. Voigt then called for the vote on the previously deferred motion to approve the recommended budget for 2001 as moved by Mr. Grennan and seconded by Mr. Voigt. This motion passed without opposition.

Agenda Item 6 – Secretary's Report

Nick Brown reported that he had not completed an assignment given to him by the Board of Directors at the last meeting for staff to recommend a formula rate for inclusion in SPP's regional tariff by this meeting. Mr. Brown offered his apology for not doing so but explained his belief that it would be inappropriate for Staff to perform this function and bypass SPP's organizational structure. Mr. Brown stated he had taken the issue to the Regional Tariff Working Group, but this was something they were not willing to take on at this time. Mr. Brown then asked for direction from the Board stating he would proceed as directed but felt going through the organizational structure would be best. After much discussion Mr. Parr moved and Mr. McDaniel seconded that the task of considering a formula rate, revenue allocation and functionalization of facilities be assigned to the Regional Tariff Working Group with an interim report due in February and a final product be presented at the May Board of Directors meeting for consideration. This motion passed unopposed.

Adjournment

At 3:20 p.m., Mr. Voigt thanked everyone for their participation and following a short break, reconvened in executive session to discuss staff matters.

Nicholas A. Brown, Corporate Secretary

Southwest Power Pool
COMMERCIAL PRACTICES COMMITTEE
Recommendation to the Board of Directors
February 20, 2001

Background

The Regional Tariff Working Group (RTWG) is responsible for maintaining SPP's Open Access Transmission Tariff (OATT). Since SPP's tariff was filed in December of 1997, numerous enhancements have been made as a result of RTWG deliberations and SPP's overall collaborative processes in which customers play a big part in making recommendations for continued improvement. Each modification must first be approved by SPP's Board of Directors and then accepted by FERC.

Analysis

Based on many months of deliberation, the RTWG is recommending revisions in six specific areas of SPP's OATT as shown in the attached document.

Recommendation

The Commercial Practices Committee recommends that the Board of Directors approve the attached modifications to SPP's Tariff and subsequent filing with the FERC.

Approved:	Regional Tariff Working Group	2/1/01
	Commercial Practices Committee	2/5/01

Action Requested: Approve Recommendation

Regional Tariff Working Group Report

Commercial Practices Committee

February 5, 2001

SPP Tariff Modification
Revisions to Attachment P

The specified changes to Attachment P are made to affect two things approved by the RTWG: to bring Attachment P timing specifications in synchronization with FERC Order 638 and to allow daily reservations to be submitted on the business day before NERC holidays and weekends. Required Order 638 changes have been made and footnote 4 has been added to allow additional lead time for reservations submitted prior to NERC holidays and weekends.

ATTACHMENT P

Transmission Service Type	**Term**	**Transmission Requests 2/** No Later Than	No Earlier Than	**SPP Response to Application**	**Determine Capacity Available or System Impact Study (From Date of Customer Commitment)**		**Customer Response** [1/]	**Energy Scheduling 2/ Changes** No Later Than	No Later Than
Long Term Firm	1 Year or More	60 Days Prior		15 days	30 days	60 days	15 days	1000 day prior	20 min prior to hour
Short-Term Firm	More than 1 month (monthly)	30 days prior	120 days prior	24 hr	30 days	60 days	4 days	1000 day prior	20 min prior to hour
Short-Term Firm	1 mo (monthly)	8 days prior	90 days prior	4 days	30 days	60 days	4 days	1000 day prior	20 min prior to hour

SPP Tariff Attachment P - Proposed

Transmission Service Type	**Term**	**Transmission Requests 2/**		**SPP Response to Application**	**Determine Capacity Available or System Impact Study (From Date of Customer Commitment)**		**Customer Response** [1/]	**Energy Scheduling 2/ Changes**	
		No Later Than	**No Earlier Than**					**No Later Than**	**No Later Than**
Short-Term Firm	More than 1 wk up to 1 month (weekly)	8 days prior	60 days prior	24 hr	30 days	60 days	48 hr	1000 day prior	20 min prior to hour

SPP Tariff Attachment P - Proposed

Transmission Service Type	**Term**	**Transmission Requests 2/**		**SPP Response to Application**	**Determine Capacity Available or System Impact Study (From Date of Customer Commitment)**		**Customer Response** [1/]	**Energy Scheduling 2/ Changes**	
		No Later Than	**No Earlier Than**					**No Later Than**	**No Later Than**
Short-Term Firm	1 wk (weekly)	2 days prior	30 days prior	24 hr	30 day	60 days	48 hr	1000 day prior	20 min prior to hour
Short-Term Firm	More than 1 day up to 1 wk (daily)	2 days prior	14 days prior	24 hr	30 days	60 days	24 hr	1000 day prior	20 min prior to hour
Short-Term Firm	1 Day (daily)	1000 day prior	3 days prior _4/	24 hrs	60 min	60 days	2 hr	1200 day prior	20 min prior to hour

SPP Tariff Attachment P - Proposed

Transmission Service Type	**Term**	**Transmission Requests 2/**		**SPP Response to Application**	**Determine Capacity Available or System Impact Study (From Date of Customer Commitment)**		**Customer Response** [1/]	**Energy Scheduling 2/ Changes**	
		No Later Than	**No Earlier Than**					**No Later Than**	**No Later Than**
Non-Firm	1 month or greater (monthly)	3 days prior	60 days prior	N/A	2 days	N/A	24 hr	1400 day prior	20 min prior to hour
Non-Firm	1 wk up to 1 mo (weekly)	2 days prior	14 days prior	N/A	4 hr	N/A	24 hr	1400 day prior	20 min prior to hour

SPP Tariff Attachment P - Proposed

Transmission Service Type	**Term**	**Transmission Requests 2/** No Later Than	No Earlier Than	**SPP Response to Application**	**Determine Capacity Available**	**or System Impact Study (From Date of Customer Commitment)**	**Customer Response [1/]**	**Energy Scheduling 2/ Changes** No Later Than	No Later Than
Non-Firm	1 day up to 1 wk (daily)	1200 day prior	2 days prior _4/	N/A	30 min	N/A	2 hr	1400 day prior	20 min prior to hour
Non-Firm	1 hour up to 1 day (hourly)	1400 day prior or later if practicable	1200 day prior	N/A	30 min	N/A	5 min	1500 day prior	20 min prior to hour
Non-Firm w/o reservation priority of Sec. 14.2	next-hour (hourly)	30 minutes prior	1 hour prior	N/A	N/A	N/A	N/A 3/	N/A 3/	N/A 3/

1/ For transactions not covered by an umbrella service agreement, the customer response must be execution of a service agreement or a request that an unexecuted service agreement be filed with the Commission pursuant to Section 15.3 of the Tariff. For transactions under an umbrella service agreement, the above times are the deadlines by which time the customer must notify The Transmission Provider of its acceptance of the offer to provide transmission.

2/ The Transmission Provider, in its discretion exercised on a non-discriminatory basis, may waive any of these requirements.

3/ All Non-Firm next-hour requests are deemed to be pre-confirmed and pre-scheduled.

4/ Excluding Sundays and NERC Holidays

ATTACHMENT P

Transmission Service Type	Term	Transmission Requests 2/ No Later Than	No Earlier Than	SPP Response to Application	Determine Capacity Available	or System Impact Study (From Date of Customer Commitment)	Customer Response [1/]	Energy Scheduling 2/ Changes No Later Than	No Later Than
Long Term Firm	1 Year or More	60 Days Prior		15 days	30 days	60 days	15 days	1000 day prior	20 min prior to hour
Short-Term Firm	More than 1 month (monthly)	31 days prior	120 days prior	24 hr	30 days	60 days	~~24 hr~~ 4 days	1000 day prior	20 min prior to hour
Short-Term Firm	1 mo (monthly)	8 days prior	90 days prior	24 hr	30~~7~~ days	60 days	~~24 hr~~ 4 days	1000 day prior	20 min prior to hour

SPP Tariff Attachment P - ~~Current~~Compared

Transmission Service Type	Term	Transmission Requests 2/		SPP Response to Application	Determine Capacity Available or System Impact Study (From Date of Customer Commitment)		Customer Response [1/]	Energy Scheduling 2/ Changes	
		No Later Than	No Earlier Than					No Later Than	No Later Than
Short-Term Firm	More than 1 wk up to 1 month (weekly)	8 days prior	60 days prior	24 hr	30~~7~~ days	60 days	48 ~~24~~ hr	1000 day prior	20 min prior to hour

SPP Tariff Attachment P - ~~Current~~Compared

Transmission Service Type	Term	Transmission Requests 2/		SPP Response to Application	Determine Capacity Available or System Impact Study (From Date of Customer Commitment)		Customer Response [1/]	Energy Scheduling 2/ Changes	
		No Later Than	No Earlier Than		Determine Capacity Available	System Impact Study		No Later Than	No Later Than
Short-Term Firm	1 wk (weekly)	2 days prior	30 days prior	24 hr	30 ~~1~~ days	60 days	48 ~~24~~ hr	1000 day prior	20 min prior to hour
Short-Term Firm	More than 1 day up to 1 wk (daily)	2 days prior	14 days prior	24 hr	30 ~~1~~ days	60 days	24 hr	1000 day prior	20 min prior to hour
Short-Term Firm	1 Day (daily)	1000 day prior	3 days prior _4/	24 hrs	60 min	60 days	~~60 min~~ 2 hr	1200 day prior	20 min prior to hour

Transmission Service Type	Term	Transmission Requests 2/ No Later Than	No Earlier Than	SPP Response to Application	Determine Capacity Available (From Date of Customer Commitment)	or System Impact Study	Customer Response [1/]	Energy Scheduling 2/ Changes No Later Than	No Later Than
Non-Firm	1 month or greater (monthly)	3 days prior	60 days prior	N/A	2 days	N/A	24 hr	1400 day prior	20 min prior to hour
Non-Firm	1 wk up to 1 mo (weekly)	2 days prior	14 days prior	N/A	4 hr	N/A	~~90 min~~ 24 hr	1400 day prior	20 min prior to hour

Transmission Service Type	Term	Transmission Requests 2/ No Later Than	Transmission Requests 2/ No Earlier Than	SPP Response to Application	Determine Capacity Available (From Date of Customer Commitment)	or System Impact Study (From Date of Customer Commitment)	Customer Response [1/]	Energy Scheduling 2/ Changes No Later Than	Energy Scheduling 2/ Changes No Later Than
Non-Firm	1 day up to 1 wk (daily)	1200 day prior	2 days prior_4/	N/A	30 min	N/A	~~90 min~~ 2 hr	1400 day prior	20 min prior to hour
Non-Firm	1 hour up to 1 day (hourly)	1400 day prior or later if practicable	1200 day prior	N/A	30 min	N/A	~~30 min~~ 5 min	1500 day prior	20 min prior to hour
Non-Firm w/o reservation priority of Sec. 14.2	next-hour (hourly)	30 minutes prior	1 hour prior	N/A	N/A	N/A	N/A 3/	N/A 3/	N/A 3/

1/ For transactions not covered by an umbrella service agreement, the customer response must be execution of a service agreement or a request that an unexecuted service agreement be filed with the Commission pursuant to Section 15.3 of the Tariff. For transactions under an umbrella service agreement, the above times are the deadlines by which time the customer must notify The Transmission Provider of its acceptance of the offer to provide transmission.

2/ The Transmission Provider, in its discretion exercised on a non-discriminatory basis, may waive any of these requirements.

3/ All Non-Firm next-hour requests are deemed to be pre-confirmed and pre-scheduled.

4/ Excluding Sundays and NERC Holidays

SPP Tariff Modification
Next Hour Market

The SPP next hour market tariff mark-up reflects the tariff modifications proposed by NERC and approved by the FERC, included in the relevant sections of SPP's Tariff. These modifications to the SPP Tariff will provide for implementation of the next hour market in SPP.

NEXT-HOUR-MARKET TARIFF PROVISIONS

1.26(a) **Next-Hour-Market Service – Non-firm transmission service that (a) is reserved for one clock hour and (b) is requested within sixty (60) minutes before the start of the next clock hour for service commencing at the start of that clock hour.**

14.2 **Reservation Priority:** Non-Firm Point-To-Point Transmission Service shall be available from transmission capability in excess of that needed for reliable service to Native Load Customers, Network Customers, and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service and customers under other transmission tariffs or agreements taking network or firm point-to point transmission service from the Transmission Owner(s). A higher priority will be assigned to reservations with a longer duration of service involving the same Points of Receipt and Delivery. In the event the Transmission System is constrained, competing requests of equal duration involving the same pints of Receipt and Delivery will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service; provided, however, this provision assigning priority based upon the highest price offered shall not affect the priority of transmission contracts not under this Tariff. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers and for network customers under Grandfathered Agreements involving the affected Transmission Owner(s) from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the **second lowest reservation priority under the Tariff, and Non-Firm Point-To-Point Transmission Service used for Next-Hour-Market Service will have the** lowest reservation priority under the Tariff.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: All scheduling practices and schedules submitted by transmission Customers will be consistent with applicable North American Electric Reliability Council Policies and SPP Criteria. Transmission Customers shall submit all schedules electronically in a form specified by the Transmission Provider. Schedules for Non-Firm Point-To-Point Transmission Service**, other than for Next-Hour-Market Service,** must be submitted to the Transmission Provider in accordance with the times in Attachment P. Schedules submitted after the applicable time specified in Attachment P will be accommodated if practicable. **Schedules for Non-Firm Point-To-Point Transmission Service for Next-Hour-Market Service must be submitted to the Transmission Provider no later than 20 minutes and no earlier than 60 minutes before the start of the next clock hour. Schedules submitted less than 20 minutes prior to the start of the next clock hour will be accommodated, if practicable.** Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per. Transmission Customers within the Transmission Owner's service area (or Control Area) with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be accommodated in accordance with Attachment P. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by the Delivering Party. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service: The Transmission Provider reserves the right to Curtail or cause to be Curtailed, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of the Transmission System or the systems directly or indirectly interconnected with the Transmission Provider's Transmission System. The Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment R. The Transmission Provider reserves the right to Interrupt (or to effect the Interruption of, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service under this Tariff or for firm transmission service provided by a Transmission Owner under a Grandfathered Agreement, (2) a request for Non-Firm Point-To-Point Transmission Service, from the same Point of Receipt to the same Point of Delivery, of greater duration under this Tariff or for non-firm transmission of greater duration provided by a Transmission Owner under a Grandfathered Agreement, (3) a request for Non-Firm Point-To-Point Transmission Service, from the same Point of Receipt to the same Point of Delivery, of equal duration with a higher price under this Tariff or for non-firm transmission of equal duration, from the same point of receipt to the same point of Delivery, with a higher price provided by a Transmission Owner under a Grandfathered Agreement, or (4) transmission service for Network Customers from non-designated resources under this tariff or under a Grandfathered Agreement. **<u>Point-to-Point Transmission Service for Next-Hour-Market Service will always have the lowest priority.</u>** The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a nondiscriminatory basis to the transaction(s) that effectively relieve the constraint; however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service under this Tariff or firm transmission service provided by a Transmission Owner under Grandfathered Agreements. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made **<u>first to Next-Hour-Market Service and then to remaining transactions beginning with those</u>** transactions of the shortest term (<u>e</u>.<u>g</u>., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a **higher priority than Next-Hour-Market Service, but will have a** lower priority than any **other** Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice. In the event that the Transmission Customer fails to cease or reduce service in response to a directive by the Transmission Provider, the Transmission Customer shall pay any applicable charges and the following penalty (in addition to the charges for all of the non-firm capacity used): 200% of the Non-Firm Point-to-Point Transmission Service Charge for the entire length of the reserved period not to exceed one month for the amount in excess of such capacity reservation. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive. These penalty revenues shall reduce the Transmission Provider's administrative costs.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service: Attachment P lists the time requirements applicable to when the requests must be made, the evaluation of the requests, and the Transmission Customer responses **and requests for Next-Hour-Market Service shall be submitted no earlier than 60 minutes before the start of the next clock hour.** Requests for service**, except for Next-Hour-Market Service,** received later than the applicable time prior to the day service is scheduled to commence **and requests for Next–Hour-Market Service submitted later than 20 minutes before the start of the next clock hour** will be accommodated if practicable.

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

Newly added Section 4 (a)

4(a) Next-Hour-Market Service: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the applicable charges posted on OASIS. In the event that transmission service is curtailed or interrupted by the Transmission Provider, either acting directly or indirectly at the request of another transmission provider or a Security Coordinator, the Transmission Customer shall be charged only for that portion of the hour of actual transmission service used. The pro-rata portion must be agreed upon between the transmission provider and the transmission customer.

SPP Tariff Modification
Proposed New Attachment Y

The EOC has approved a three-phase implementation of a proposal to increase transmission utilization. The proposal rests on the premise that a flow reservation and a counter-flow reservation would exist as a pair that would necessarily be used simultaneously. Alternatively, where multiple reservations impact a constrained Flowgate, simultaneous use would be foregone.

At its January 18, 2001 meeting, the RTWG examined an implementation plan for this proposal and a draft Attachment Y Tariff modification to implement it. The RTWG approved development of an experimental Tariff modification that provides for the implementation of the first phase. In the event that additional phases are implemented, modifications to this Attachment Y will be made.

ATTACHMENT Y

Flexible Use Transmission Service (Experimental)

1. Introduction

1.1. Definitions

In addition to the definitions set out in Section I. 1. of this Tariff, the following definitions apply to this Attachment Y.

1.1.1. Constrained Flowgate - a flowgate whose loading or projected loading exceeds its rating less any appropriate margins.

1.1.2. Counter-Flow Reservation - a new request for transmission service or existing transmission reservation that has an unloading effect on the Constrained Flowgate. A Counter-Flow Reservation is a Relieving Reservation to the extent that it is used simultaneously with the Restricted Reservation.

1.1.3. Positive-Flow Reservation – an existing transmission reservation that has a loading effect on the Constrained Flowgate in the same direction as a Restricted Reservation. A Positive-Flow Reservation is a Relieving Reservation to the extent that its use is foregone simultaneously with the use of a Restricted Reservation.

1.1.4. Relieving Reservation – a new or existing firm reservation for transmission service that effectively removes the constraining flow caused by the Restricted Reservation on the Constrained Flowgate(s). Such reservation may be one that the Customer owns or has made the necessary arrangements to use for such purpose or one which has been redirected pursuant to Section 22 of this Tariff for the purpose of obtaining new service under this Attachment Y.

1.1.5. Restricted Reservation – a request for regional transmission service that cannot be accepted by SPP due to lack of ATC on one or more flowgates, but that may be accepted under the provisions of this Attachment Y.

1.2. Nature of Service

If a Firm Point-To-Point Transmission Service request cannot be accommodated by SPP due to lack of ATC on one or more flowgates the Customer may submit or designate a Relieving Reservation that removes the constraining effects of the Restricted Reservation. The Relieving Reservation is analyzed for its effect on the Constrained Flowgate(s) and all other flowgates to ensure that it sufficiently offsets the impact of the Restricted Reservation and does not cause any other flowgates to become constrained. If the Relieving Reservation is approved, the Restricted Reservation will be approved also. When the Restricted Reservation is scheduled, SPP will determine how much, if any, of the Relieving Reservation must be or can be scheduled on a day-ahead basis to maintain flows on the constraint within its loading limits. SPP will not approve the Restricted Reservation schedule until the appropriate Relieving Reservation schedule is approved (in the case of a Relieving Reservation, submittal of the reduced schedule will suffice).

There are two types of Relieving Reservations that may be used to allow acceptance of the Restricted Reservation. The Customer may create a Relieving Reservation by submitting one or more requests with counter-flow impacts equal to or greater than the impacts of the Restricted Reservation on the Constrained Flowgate(s). This type is a

Counter-Flow Reservation and may be submitted as a new request for service or a commitment to use an existing reservation. When necessary, a Counter-Flow Reservation must be scheduled simultaneously with the Restricted Reservation. The Customer may use the second type of Relieving Reservation by identifying an existing confirmed reservation owned by the Customer with positive-flow effects that are equal to or greater than the constraining effects of the Restricted Reservation on the Constrained Flowgate(s). This type is a Positive-Flow Reservation that, when necessary, will not be scheduled for use simultaneously with the use of the Restricted Reservation.

Only SPP reservations will be eligible for consideration as a Relieving Reservation.

Service under this Attachment Y shall be provided only for point-to-point transactions.

2. Experiment Description

This Flexible Use Transmission Service is hereby implemented on an experimental basis.

During the experiment, Restricted and Relieving reservation pairs will be limited to monthly, and weekly firm reservations having service periods which end not later than the end of the experiment.

The duration of the experiment shall be one (1) year after the effective date of this Attachment Y. In the course of the experiment, SPP will assess the merit of continued offering of this service.

3. Use of Paired Reservations

3.1. Establishing Paired Reservations

There are two types of paired reservations, a Restricted Reservation associated with a corresponding Counter-Flow Relieving Reservation and a Restricted Reservation associated with a corresponding Positive-Flow Relieving Reservation.

3.2. Paired Reservation Submittal Procedures

The Customer may submit a Relieving Reservation in the form of a Counter-Flow Reservation. The Counter-Flow Reservation may either be a new request submitted by the Customer or it may be an existing reservation that the Customer already owns or has made the necessary arrangements to use. If an existing reservation is to be used as a Counter-Flow Reservation the Customer must inform SPP by including the OASIS reference number of the existing Counter-Flow Reservation and the capacity to be assigned as a counter-flow along with the Restricted Reservation request. The capacity, or any fraction thereof, of a Counter-Flow Reservation may be linked to only one Restricted Reservation.

As an alternative to submitting a Counter-Flow Reservation, a Customer may submit an existing reservation with positive flow effects on the Constrained Flowgate(s) that are equal to or greater than the constraining effects of the Restricted Reservation. The Positive-Flow Reservation should be one that the Customer owns or has been assigned. By using a Positive-Flow Reservation as the Relieving Reservation, the Customer is giving up rights to use that reservation concurrently with the Restricted Reservation when necessary.

If a Positive-Flow Reservation is to be used as a Relieving Reservation, the Customer must inform SPP by including the OASIS reference number of the Positive-Flow

Reservation and the capacity to be assigned as a Relieving Reservation along with the Restricted Reservation request. The capacity, or any fraction thereof, of a Positive-Flow Reservation may be linked to only one Restricted Reservation.

4. Charges for Flexible Use Transmission Service

Customers shall be billed for all reservations made or used pursuant to the provisions of this Attachment Y, as well as associated losses and ancillary services, in accordance with this Tariff.

5. Scheduling Requirements

When a Customer schedules against a Restricted Reservation, a tag must be submitted to SPP by the scheduling deadline for firm transmission service. SPP will not approve the tag until all firm schedules are known. After the scheduling deadline, SPP will use OASIS Automation to determine if the Constrained Flowgate(s) for which the Restricted Reservation has been purchased is (are) projected to be constrained for the next day. If the flowgate(s) is (are) projected to be constrained and a Counter-Flow Reservation is linked with the Restricted Reservation, SPP will establish the hourly counter-flow schedule profile necessary to relieve the Constrained Flowgate(s). The amount of constraining flow that must be relieved is the product of the amount by which the Constrained Flowgate is overloaded by firm transactions and the ratio of the contribution to flowgate loading of the Restricted Reservation schedule to the total contribution to flowgate loading of all Restricted Reservation schedules. If OASIS Automation does not project the Constrained Flowgate to be overloaded for the next day, no counter-flow schedule will be required. If OASIS Automation indicates that a counter-flow schedule will be required for the next day, the hourly profile of that schedule will be capped at the capacity of the Counter-Flow Reservation. The NERC MRD tag format or other similar format will be used to schedule the Counter-Flow Reservation. The Counter-Flow Reservation schedule must be submitted by the scheduling deadline for non-firm transmission service. If a Counter-Flow Reservation schedule is not received by that deadline, the Restricted Reservation schedule will be canceled.

If the Constrained Flowgate(s) is (are) projected to be constrained, and a tag using the Positive-Flow Reservation was submitted and approved prior to the scheduling deadline, SPP will establish the maximum hourly Restricted Reservation schedule profile that may flow simultaneous with the Positive-Flow Reservation schedule. The amount of constraining flow that must be relieved is the product of the amount the Constrained Flowgate is overloaded by firm transactions and the ratio of the contribution to flowgate loading of the Restricted Reservation schedule to the total contribution to flowgate loading of all Restricted Reservation schedules. This amount of relief will be achieved by curtailing the appropriate amount of the Positive-Flow Reservation schedule or the Restricted Reservation schedule. If no tag using the Positive-Flow Reservation was submitted and approved or if OASIS Automation does not project the Constrained Flowgate (s) to be overloaded, the Restricted Reservation schedule will be allowed to flow. Once the amount of Restricted Reservation and Positive-Flow Reservation that can be simultaneously scheduled is set, SPP will not approve any additional simultaneously scheduled amount.

6. Curtailment of Restricted and Relieving Reservations

If TLR occurs on the Constrained Flowgate for which a Restricted Reservation schedule and its associated Counter-Flow Reservation schedule are flowing, SPP will not curtail the transaction unless it is determined that the counter-flow is not effective. In this case, it would be curtailed proportionately with all other firm transactions. If the Restricted Reservation schedule is curtailed, the Customer will have the choice of interrupting the Counter-Flow Reservation schedule. If the Counter-Flow Reservation schedule is curtailed due to TLR, the Restricted Reservation schedule will also be curtailed. If the Restricted Reservation schedule is curtailed due to TLR on a flowgate other than the flowgate(s) for which the Counter-Flow Reservation is arranged to protect, the Customer will have the option of interrupting the Counter-Flow Reservation schedule.

7. Redirection of Service Provided Hereunder

Firm Relieving and Restricted Reservations may be redirected to any unconstrained path, pursuant to Section 22 of this Tariff. Additionally, such reservations may be redirected to a constrained path, provided that a corresponding new Relieving Reservation is established.

SPP Tariff Modification
Section 13.7

A recent scheduling error by a customer prompted the RTWG to consider and ultimately approve a change in section 13.7 of the tariff to include a penalty provision in the amount of 200% of the actual excess use. In conjunction with that change, the RTWG directed SPP Staff to implement a scheduling software revision that would permit it to compare all schedules to corresponding reservations and reject all over-schedules.

Proposed RTWG Language

13.7(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. In the event that a Transmission Customer (including Third-Party Sales by a Transmission Owner) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay the following penalty (in addition to the applicable charges for all of the firm capacity actually used): 200% of the Firm Point-to-Point Transmission Service charge for the period for which the additional service was actually used. The charges for the additional service shall be based upon the duration of the period when the additional capacity was used. For example, one hour would be billed at the charge for weekday deliveries. The Transmission Provider shall compensate the Transmission Owners for 100% of the Firm Point-to-Point Transmission Service charge for the period for which they have provided service. The penalty revenues in excess of that amount shall be used to reduce the Transmission Provider's administrative costs. For the amounts exceeding reserved capacity, the Transmission Customer also must replace losses as required by this Tariff.

[13.7(c)] The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. In the event that a Transmission Customer (including Third-Party Sales by a Transmission Owner) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay the following penalty (in addition to the **[applicable]** charges for all of the firm capacity **[actually]** used): 200% of the Firm Point-to-Point Transmission Service charge for the ~~{entire length of the reserved period but not exceeding one month for the amount in excess of such reserved capacity}~~ **[period for which the**

additional service was actually used. The charges for the additional service shall be based upon the duration of the period when the additional capacity was used. For example, one hour would be billed at the charge for weekday deliveries]. The Transmission Provider shall compensate the Transmission Owners for 100% of the Firm Point-to-Point Transmission Service charge for the period for which they have provided service. The penalty revenues in excess of that amount shall be used to reduce the Transmission ~~{Providers}~~ **[Provider's]** administrative costs. For the amounts exceeding reserved capacity, the Transmission Customer also must replace losses as required by this Tariff.

SPP Tariff Modification
Sections 2.2 and 22
Revised

Subsequent to extensive discussion of right-of-first-refusal issues by the RTWG, it recommends the specified changes to sections 2 and 22 of the SPP Tariff. These changes have been made to clarify the rights and obligations of incumbent and new customers and clarify challenge procedures.

A minor revision to the language was approved by the RTWG at its February 1, 2001 meeting. The Tariff segments attached hereto reflect those approved revisions.

2.2 Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more, and retail) of the Transmission Owner(s) or Transmission Provider have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Owner(s) or elects to purchase capacity and energy from another supplier. If at any time during the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service, the existing firm service customer must agree to accept a contract term at least equal to the longest term competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer. This reservation priority only applies to the facilities of the Transmission Owner(s) where such facility costs have been included as part of the firm service rates that the firm service customer has been paying. If competing existing firm service requirements customers apply for service that cannot be fully provided, the priority rights will be ranked in accordance with first-come, first-served principles. If firm service customers tie, then the capacity for which they receive priority rights under this Tariff shall be apportioned on a pro rata basis.

2.3 Procedures For Exercising Transmission Reservation Priority Rights:

(a) If, at any time, the Transmission Provider receives a request from an Eligible Customer for new firm transmission service that the Transmission Provider determines it could not accept without performing a System Impact Study if an existing customer were to exercise its transmission reservation priority pursuant to Section 2.2, the Transmission Provider shall notify such Eligible Customer that execution of a contingent service agreement shall be required within fifteen (15) days of such notification. Such service agreement shall be contingent on the outcome of these procedures. The Transmission Provider shall concurrently notify the existing customer of the new request. Within sixty (60) days after written notification by the Transmission Provider of execution of a contingent service agreement by the competing customer, the existing customer must inform the Transmission Provider whether it exercises its reservation priority pursuant to Section 2.2 and agrees to accept a contract term at least equal to the new request for the amount of the competing request. For amounts of service in excess of those sought in the competing request(s), the existing customer shall maintain its reservation priority without taking any further action except for those actions required under Section 2.3 (c) or in response to future competing requests. In the event an existing customer does not exercise its reservation priority or fails to respond within such time period, the existing firm service customer shall forfeit its reservation priority to the competing customer(s). In the event that the competing customer(s) do not reserve all of the forfeited rights of the existing customer, the reservation priority will return to the existing customer.

(b) In the event that a System Impact Study is necessary, the customer that is provided the reservation shall bear the cost of the study except to the extent that the competing customer is provided any portion of its reservation. In such instance the competing customer shall bear the cost of the study.

(c) In the event an existing firm service customer does not receive a notification pursuant to Section 2.3(a), then the existing customer must notify Transmission Provider no later than sixty (60) days prior to the end of the term of its firm transmission contract that it is exercising its transmission reservation priority and will take transmission service for an additional term of one year or longer; otherwise it shall forfeit the transmission reservation priority associated with the contract.

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Point-To-Point Transmission Service may request the provision of transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement for Long-Term Firm Transmission Service or the confirmed Application for Short-Term Transmission Service ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-to-Point Transmission Service charge (except as provided in Section 22.1a) or executing a new Service Agreement for Long-Term Firm Transmission Service or submitting a new Application for Short-Term Firm Transmission Service, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or under any other transmission tariff or agreement where the service is being provided by the Transmission Owner or by the Transmission Owner on behalf of its (their) Native Load Customers.

(b) The sum of all Firm and Non-Firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement for Long-Term Firm Transmission or Application for Short-Term Firm Transmission Service under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement for Long-Term Firm Transmission or Application for Short-Term Firm Transmission Service in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.1a Additional Charge To Prevent Abuse: If a Transmission Customer making the modifications in Section 22.1 takes service over a transmission path that costs more than the path the Transmission Customer initially reserved, then for the service the Transmission Customer schedules, the Transmission Customer shall pay in addition to the amounts based on its initial reservation the additional costs (i.e., the difference between the zonal rates) associated with the new path. In addition, the Transmission Customer shall replace losses (in accordance with Attachment M) and pay for any redispatch costs (as determined in accordance with Attachment K) based on the actual transmission path used.

22.2 Modification On a Firm Basis: Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement for Long-Term Firm Transmission Service or confirmed Application for Short-Term Firm Transmission Service. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement for Long-Term Firm Transmission Service or confirmed Application for Short-Term Firm Transmission Service. In any instance where the remaining term of service, after modification pursuant to this provision, is less than twelve (12) months the transmission customer will not have rights of reservation priority.

2.2 Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more, and retail) of the Transmission Owner(s) or Transmission Provider have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Owner(s) or elects to purchase capacity and energy from another supplier. If at ~~{the end of}~~ **[any time during]** the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service, the existing firm service customer must agree to accept a contract term at least equal to ~~{a}~~ **[the longest term]** competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer. This reservation priority only applies to the facilities of the Transmission Owner(s) where such facility costs have been included as part of the firm service rates that the firm service customer has been paying. If competing existing firm service requirements customers apply for service that cannot be fully provided, the priority rights will be ranked in accordance with first-come, first-served principles. If firm service customers tie, then the capacity for which they receive priority rights under this Tariff shall be apportioned on a pro rata basis.

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(a) If, at any time, the Transmission Provider receives a request from an Eligible Customer for new firm transmission service that the Transmission Provider determines it could not accept without performing a System Impact Study if an existing customer were to exercise its transmission reservation priority pursuant to Section 2.2, the Transmission Provider shall notify such Eligible Customer that execution of a contingent service agreement shall be required within fifteen (15) days of such notification. Such service agreement shall be contingent on the outcome of these procedures. The Transmission Provider shall concurrently notify the existing customer of the new request. Within sixty (60) days after written notification by the Transmission Provider of execution of a contingent service agreement by the competing customer, the existing customer must inform the Transmission Provider whether it exercises its reservation priority pursuant to Section 2.2 and agrees to accept a contract term at least equal to the new request for the amount of the competing request. For amounts of service in excess of those sought in the competing request(s), the existing customer shall maintain its reservation priority without taking any further action except for those actions required under Section 2.3 (c) or in response to future competing requests. In the event an existing customer does not exercise its reservation priority or fails to respond within such time period, the existing firm service customer shall forfeit its reservation priority to the competing customer(s). In the event that the competing customer(s) do not reserve all of the forfeited rights of

the existing customer, the reservation priority will return to the existing customer.

(b) In the event that a System Impact Study is necessary, the customer that is provided the reservation shall bear the cost of the study except to the extent that the competing customer is provided any portion of its reservation. In such instance the competing customer shall bear the cost of the study.

(c) In the event an existing firm service customer does not receive a notification pursuant to Section 2.3(a), then the existing customer must notify Transmission Provider no later than sixty (60) days prior to the end of the term of its firm transmission contract that it is exercising its transmission reservation priority and will take transmission service for an additional term of one year or longer; otherwise it shall forfeit the transmission reservation priority associated with the contract.]

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Point-To-Point Transmission Service may request the provision of transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement for Long-Term Firm Transmission Service or the confirmed Application for Short-Term Transmission Service ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-to-Point Transmission Service charge (except as provided in Section 22.1a) or executing a new Service Agreement for Long-Term Firm Transmission Service or submitting a new Application for Short-Term Firm Transmission Service, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or under any other transmission tariff or agreement where the service is being provided by the Transmission Owner or by the Transmission Owner on behalf of its (their) Native Load Customers.

(b) The sum of all Firm and Non-Firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement for Long-Term Firm Transmission or Application for Short-Term Firm Transmission Service under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement for Long-Term Firm Transmission or Application for Short-Term Firm Transmission Service in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.1a Additional Charge To Prevent Abuse: If a Transmission Customer making the modifications in Section 22.1 takes service over a transmission path that costs more than the path the Transmission Customer initially reserved, then for the service the Transmission Customer schedules, the Transmission Customer shall pay in addition to the amounts based on its initial reservation the additional costs (i.e., the difference between the zonal rates) associated with the new path. In addition, the Transmission Customer shall replace losses (in accordance with Attachment M) and pay for any redispatch costs (as determined in accordance with Attachment K) based on the actual transmission path used.

22.2 Modification On a Firm Basis: Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement for Long-Term Firm Transmission Service or confirmed Application for Short-Term Firm Transmission Service. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement for Long-Term Firm Transmission Service or confirmed Application for Short-Term Firm Transmission Service. **[In any instance where the remaining term of service, after modification pursuant to this provision, is less than twelve (12) months the transmission customer will not have rights of reservation priority.]**

SPP Tariff Modification
TLR Procedures - Attachment R

The TLR Procedures, currently incorporated in SPP's Tariff as Attachment R, have been modified by NERC. The RTWG recommends a modification to Attachment R, taking one of two forms. The current Attachment R may be replaced by a statement referencing "currently effective NERC TLR procedures" and might including a reference to the NERC website. Alternatively, the current TLR procedures may be included in the Tariff as Attachment R. In determining the preferred option, consideration might be given to the fact that the TLR procedures have been changing at least annually.

Southwest Power Pool
COMMERCIAL PRACTICES COMMITTEE
Recommendation to the Board of Directors
February 20, 2001

Background

The Congestion Management Systems Working Group (CMSWG) was formed to design real-time rules for market based congestion management within SPP.

Analysis

Based on several months of deliberation, the CMSWG published the attached white paper on market design and is recommending approval of the following cornerstone principles to guide their continued work:

<u>Cornerstone principles for Real Time Market Design:</u>

- Balanced/unbalanced schedules;
- Covered/uncovered transmission;
- Physical transmission rights function as financial rights;
- LMP is ex-post based on actual generation and load;
- Aggregation of bilateral and spot;
- RTO responsible for reliability, scheduling, load forecasting; and
- Minimize the RTO's need to take a financial position.

<u>Cornerstone principles for Forward Markets:</u>

- SPP issues Financial Congestion Hedges (FCH);
- Schedules and physical delivery permitted without rights; and
- The holder of FCH is paid rents or revenues collected from customer for congestion minus payments made to generators to relieve congestion.

<u>Cornerstone principles for conversion of existing transmission rights:</u>

- Existing agreements do not lose benefits;
- All firm wholesale and retail customers are entitled to a share of the FCHs;Same priority of service for all SPP transmission w/ POW inside SPP; and
- Transactions w/ POW inside SPP curtailed on a non-discriminatory basis.

Recommendation

The Commercial Practices Committee recommends that the Board of Directors approve the CMSWG cornerstone principles to guide their continued work on real-time market design.

Approved:	Congestion Market Settlement Working Group	1/24/01
	Commercial Practices Committee	2/5/01

Action Requested: Approve Recommendation

SPP RTO Real Time Market Design

Report from the Congestion Management Systems Working Group to the Commercial Practices Committee

February 2001

EXECUTIVE SUMMARY

This paper provides a description of the recommended real time market and the associated real time congestion management system developed by the Congestion Management Systems Working Group for the SPP RTO.

The fundamental features of the recommended design are as follows:

- Allowing market participants maximum flexibility in arranging their transactions, while providing SPP with the tools to ensure system reliability.

  - The design allows equally for bilateral and spot purchases as well as self-scheduling of generation.
  - The real time market structure supports financial instruments (to be described in a later report) that allow participants to manage price risks associated with both energy and transmission.

- The real time market and congestion management system is based on the locational marginal pricing methodology.

  - Congestion will be transparently managed by allowing prices to fluctuate rather than through a process of physically restricting generation or transmission.
  - The design will lead to the creation of a spot energy market where the effects of congestion are reflected in prices.

- Spot energy prices will be based on actual supply and demand.

  - The market design will ensure that spot energy prices reflect actual dispatch.
  - The spot energy prices will be used in settlements for balancing energy as well as other uses.
  - Spot energy prices will provide meaningful information for both short run (i.e. generation, consumption, maintenance) and long run (i.e. investment) decisions.

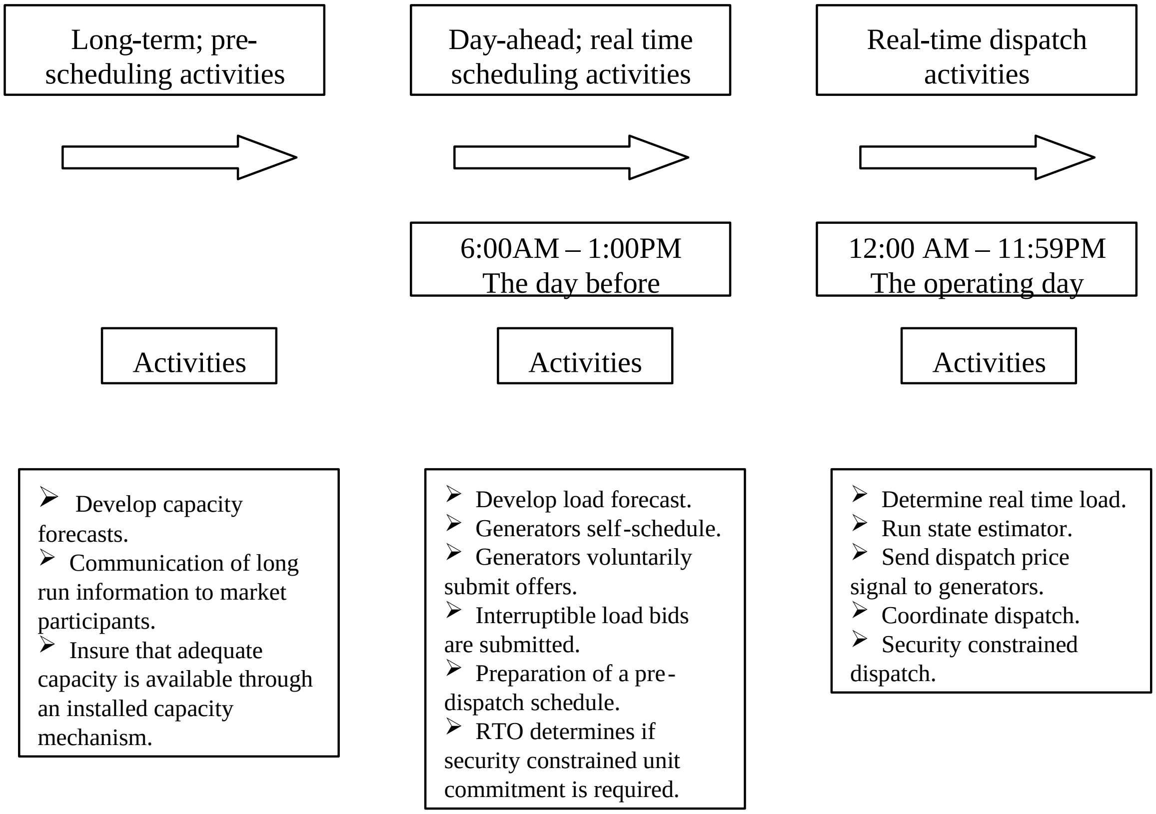
- The recommended market design is consistent with maintaining multiple control areas.

- The design will support the creation of both “trading” hubs and aggregated zones to ensure that robust and liquid spot and forward markets are allowed to develop.

- The basic design has been implemented and, to date is operating successfully in other regional markets.

The basic operational elements of the real time market are scheduling and dispatch. The paper defines the precise process by which generating units are scheduled and dispatched to meet load and maintain system reliability in the most economical manner. This process is captured in the following diagram:

Operation of the Recommended Real Time Market



Since in some ways this market design represents a substantial change from the current operating practices as well as those recommended by the Market Settlement Working Group for the interim market, the timeline for implementation is an important component of the overall design. The CMSWG has operated under the assumption that the real time congestion management system must be in place by December 15, 2002 and, as pointed out in the timeline below, significant work remains to be completed in order to meet this deadline.

Congestion Management System
Implementation Timeline

Milestones	2001				2002				2003		
	1st Q	2nd Q	3rd Q	4th Q	1st Q	2nd Q	3rd Q	4th Q	1st Q	2nd Q	3rd Q
CMSWG White Paper (07/01)	------------	--------X									
CMSWG Market Rules (10/01)	X--	-------------	-------X								
Develop RFP (09/01)		X--------	--X								
RTWG Modify Tariff (11/01)		X-	------------	--X							
Contract Awarded (12/01)			X-----	--------X							
CPC & BOD Approval (12/01)				X X							
File Tariff Changes (12/01)				X							
FERC Approval (01/02)					X						
Develop HW & SW (08/02)				X----	------------	------------	------X				
Testing & Market Trial (12/02)						X	------------	-----X			
LMP Spot Market Operational (12/02)								X			
Modify System as needed (06/03)								X-----	-------------	------------	X

TABLE OF CONTENTS

1.0 INTRODUCTION

The purpose of this paper is to provide a high level description of the recommended real time market and congestion management system developed by the Congestion Management Systems Working Group (CMSWG)[1] for the SPP RTO. Throughout the process of developing this market design, it has been explicitly recognized that the delivery of electrical power and the management of congestion[2] (i.e. redispatch) cannot be meaningfully separated in real time. With this in mind, the Group approached the task of writing the market rules by identifying the following three generic components of a congestion management system:

- Issues related to real time dispatch (i.e. the real time or spot market);
- Issues related to the management of price risks arising from redispatch (i.e. the forward market); and
- The relationship or transition between the forward and real time markets.

Inherent in the real time matching of supply and demand (i.e. the real time market) are several types of physical and financial risks.

- Supply risk - the physical risk that generation and transportation assets will not be able to meet contractual positions;
- Demand risk – the physical risk that arises from load volatility;
- Delivery risk – the physical risk that the “transport” system will not be able to match supply and demand; and
- Price risk – the financial risk that real time prices may, and usually will, be different from contract prices negotiated prior to dispatch.[3]

Ultimately, the SPP RTO Tariff and the associated Operating Guides will provide a mechanism for managing some or all of these risks. For example, while the rules pertaining to scheduling will provide a (partial) mechanism for managing the physical supply and demand risks, those pertaining to dispatch will create a mechanism for managing delivery risk.

In identifying the three generic components of a congestion management system, the Group explicitly recognized the benefits to participants in designing a market that would allow the various risks to be managed by those most able to do so. As a result, the Group felt it beneficial

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[1] The CMSWG (formerly Market Rules Working Group) was established by the SPP Board of Directors on August 30, 2000 and was tasked with developing the market rules for the “hybrid” congestion management system adopted by the Board on August 30, 2000. Under the SPP governance structure the CMSWG reports to the Commercial Practices Committee.

[2] Congestion, like system stability or voltage requirements, is a type of transmission constraint.

[3] While credit risk is extremely important it is not directly related to the dispatch process.

for the design exercise to uncouple the rules pertaining to *physical* delivery from the *financial* management of the associated price risk that arises as a result of transmission constraints, including congestion. While the final congestion management *system* for the RTO will be dependent on the market rules for all three components, the focus of this paper is on the first of these issues. As such, this paper does not address forward markets in energy or transmission rights.

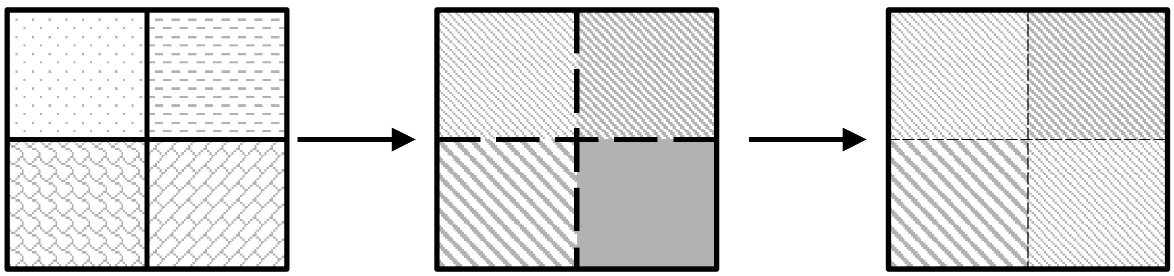
Since the basis of the real time market is physical delivery, the emphasis of this paper is on the dispatch process and the supporting day-ahead activities that are necessary to ensure the real time balancing of physical supply and demand[4]. Because a market is only as good as the price signals that it creates, it is important that prices in the spot market reflect the supply and demand conditions that existed in real time – in other words the spot prices should be consistent with the actual (rather than anticipated) dispatch.

Finally, as shown in Figure 1[5] the Southwest Power Pool is evolving from a group of predominantly independent regionalized markets into a larger integrated electricity market. This evolution is being driven as much by legislative and regulatory changes as it is by technological advances and it is important that the ultimate market design be capable of delivering the benefits that consumers expect. The recommended real time spot market design will facilitate this outcome because it;

- Provides the dispatcher with the tools to efficiently manage congestion;
- Creates a transparent spot price that mirrors dispatch; and
- Allows participants freedom of choice over how they manage their risk.

[4] Physical supply/demand is in contrast to financial supply/demand where two parties may have a contract with each other for the "supply" and "demand" of electricity but that does not mean the supplier need be the physical producer or that the demander need be the party that physically consumes the electricity.
[5] The "contiguous boxes" in the Figure represent individual control areas or integrated utilities.

FIGURE 1: Evolution of the regional electricity markets.



Initial Condition: Four geographically contiguous, but self sufficient regions. Very little integration across regions.

After Order 888: Regional difference smaller but still large.

After Order 2000: Similar dispatch, congestion management, etc. Regional differences fade. Larger market.

2.0 CORNERSTONES OF THE MARKET DESIGN

In order to facilitate the design process, the CMSWG adopted a strategy that focused initially on debating, and then finally on agreeing to, a set of "cornerstones" for the ultimate design. These cornerstones are the foundation upon which the market design is based on. In other words, to the largest extent possible the market design flows logically from these cornerstones.

- Under the SPP RTO real time market cornerstones, the market should:

1. *Support balanced/unbalanced and covered/uncovered schedules that allow load to take full advantage of spot market resources.*

    - Implicit in this cornerstone is the belief that the market rules should not bias participants to either enter into bilateral contracts or exchange through the spot market.

2. *Support forward physical transmissions rights that function as financial rights and establish priority in cases of TLR.*[6]

    - Any transmission rights exchanged in the forward market will not affect physical dispatch in real time. The rights will have financial effects but no direct physical effect.

3. *Support real-time LMP pricing as ex post based on actual total demand and actual total generation.*

[6] At the time the cornerstones were being developed, most of the discussion within the CMSWG had been focused on the real time market. As such, the appropriate definition of either physical or financial transmission rights had not been created. For the past two months there has been considerable discussion on these issues and this may or may not lead to a re-evaluation of the precise wording/meaning of this cornerstone.

➢ Consistent with the congestion management model adopted by the Board of Directors (and included in the RTO filing), the real time market will be based on locational marginal prices with prices being established by actual[7] rather than expected market conditions.

4. *Support the real time market as an aggregation of bilateral and spot supplies.*

➢ The real time market will be based on the aggregation of bilateral and spot transactions. Participants will be free to self-schedule, bid in bilateral contract positions at a zero price, or enter a price-offer curve for supply.

5. *Support the RTO's role as physical coordinator responsible for reliability, scheduling, dispatch, and SPP load forecasting.*

➢ The SPP RTO spot market will be a centrally dispatched market with the RTO serving as the coordinator.

6. *Minimize the RTO's need to take a position in the real time energy markets.*

➢ The market rules will minimize the need for the RTO to take a financial position in the market.

The cornerstones themselves provide a reasonably clear picture of the market described in the rest of the paper.

3.0 THE REAL TIME LOCATIONAL MARGINAL PRICE SPOT MARKET

The recommended real time market is illustrated in Figure 2.[7]

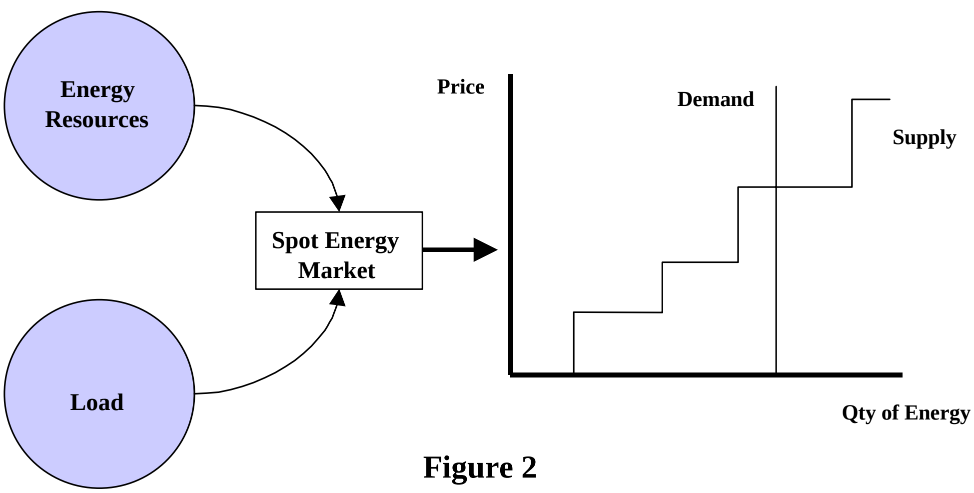


Figure 2

[7] Actual market conditions will be as determined by the SPP RTO State Estimator.

Since, in real time, physical supply and demand are equilibrated through the dispatch process, the product that is being exchanged is delivered energy[8], i.e. supply, demand, and dispatch information are all reflected in the price. This means that the actual spot price is created by the intersection of the supply and demand curves in combination with the actions of the dispatcher in real time. This price will reflect the "tool" used by the dispatcher to match supply and demand in real time and is embodied in the locational marginal price methodology (LMP). From the perspective of dispatch, LMP views all generation as being supplied to a single "bathtub".[9] The algorithm behind LMP will find the "optimal"[10] way to supply balancing energy to each node from the offers received by the SPP RTO. As transmission constraints (including congestion) arise, prices on either side of the constraint will begin to deviate. Assuming that the objective function is least cost dispatch, the LMP model will look for the lowest cost way to meet demand at each node (holding demand constant at every other node). Congestion is, therefore, managed by allowing prices to fluctuate. As prices rise on one side of a constraint, higher priced generation from different locations will be used to meet the demand that, because of the constraint, cannot be met from lower priced generation.

Because the market will deliver prices that reflect not only supply and demand conditions but also the actions of the dispatcher, there will not be a single physical price but rather a price at each node.[11] However, the voluntary nature of the market means that participants will be able to choose what, if any, percentage of their transactions are exposed to spot price risk. Consistent with the cornerstones , the RTO will not be in the position to purchase/sell energy on behalf of participants who are either long or short in real time. Rather it is the participants themselves who will be responsible for the financial effects of their decisions. Thus, for example, if a participant decides to manage their price risk by purchasing 10% of their load requirement from the spot market, it will not be the RTO who purchases this energy, but the individual participant.[12]

Implicit in the implementation of a locational marginal pricing system and the recommended real time spot market is the shift from the existing OATT to a two-part tariff. Transmission users will be charged both for access charges as well as for congestion. Depending on how existing transmission service agreements are handled, all load within the SPP RTO will take network service and will pay for congestion implicitly through spot purchases or explicitly through the payment of the difference in the LMPs at the point of injection and the point of withdrawal on bilateral transactions. Point-to-point bilateral transactions will pay explicit congestion charges through the payment of the difference in the point of injection and the point of withdrawal LMPs on bilateral transactions.

4.0 THE SCHEDULING AND DISPATCH PROCESS

[8] What this means is that the horizontal axis in the supply/demand diagram measures the quantity of delivered energy.

[9] From a physical point of view, this is consistent with the fact that electricity is a homogeneous good and it really does not matter who produced it.

[10] Optimal is in quotes because the precise definition depends on the stated objective function.

[11] This does not imply that quantities will necessarily be settled using prices from each node. For example, quantities might be settled on a zonal basis using the load-weighted average of nodal prices.

[12] Settlement rules will need to identify the counter-party and the flow of payments.

The LMP Spot Market provides users of the SPP RTO transmission system:

- Assurance of a reliable system through the management of transmission congestion;
- Market participants the ability to provide their own arrangements to meet obligations;
- Market participants the ability to sell to, or purchase from, the LMP Spot Market;
- Assurance of energy delivery; and
- Locational energy price discovery.

This section provides an overview of the activities needed to accomplish these objectives – primarily the scheduling and dispatch of generating units to reliably deliver the energy to load and meet bilateral transaction arrangements. Details of each activity are provided in later sections.

The scheduling and dispatch of generating units to meet system requirements in the most economical and reliable fashion is the culmination of many separate activities concerning:

- Load forecast and load distribution on the transmission system;
- Bilateral transactions;
- Transmission system capability and availability;
- Generation quantities and location on the transmission system; and
- Application of the market rules to assure generation is dispatched to meet load while respecting limitations of the power system.

Each of these activities is accomplished in three separate time frames: long term (pre-scheduling), day ahead (scheduling) and real time (dispatch).

In the long term, Load Serving Entities (LSE) forecast their expected load obligations and arrange for Planning Reserves to meet their load forecast. The requirement to arrange for Planning Reserves is consistent with SPP and NERC guidelines and is a practice that will continue in all states without retail choice. To ensure sufficient capacity is available to meet forecasted load and to maintain consistency across all of the SPP RTO, Load Serving Entities in retail choice states will be required to arrange for Planning Reserves. The Planning Reserve requirement is also referred to as an Installed Capacity requirement or ICAP. The details of implementing a capacity requirement are beyond the scope of this paper and require further evaluation. The SPP RTO also develops a long-term forecast of load to monitor the overall forecast/installed generation situation. The availability of and planned outages for generators designated as ICAP units are reported to SPP RTO.

The Day-ahead time frame results in the scheduling of available generation to meet the load forecast and net interchange for the next day. LSEs develop their own load forecast, self-schedule generation that may or may not meet that forecast and report their self-scheduled generation to SPP RTO. It is assumed that LSEs whose self-scheduled generation does not meet its forecasted load will be purchasing from the LMP Spot Market to make up the difference. Also, LSEs whose self-scheduled generation does not meet its real-time load will purchase energy from the LMP Spot Market to meet its load obligations. In that same time frame SPP RTO performs a Security Constrained Unit Commitment (SCUC) to assure enough generating capability will be on-line to meet forecasted total system load. A significant aspect of the SCUC process is the assurance that committed generation is located to adequately relieve any expected congestion on the SPP RTO transmission system. To perform the SCUC, SPP RTO must develop a load forecast for the next day and commit generation to meet that load forecast taking into consideration transmission congestion encountered through load magnitude and its distribution on the transmission system, generation magnitude and distribution including self-scheduled generation, and transmission limitations and constraints.

In the real-time frame, LSEs dispatch their self-scheduled generators to meet their real-time load. SPP RTO performs a near term forecast of expected real-time load, develops and publishes real-time nodal energy price signals. Generators and load use these prices to decide whether to increase or decrease their participation in the market. A significant aspect of the real-time nodal energy price development is the requirement that SPP RTO develop price signals for generators to relieve transmission congestion.

The following sections concentrate on the day-ahead scheduling requirements and real-time dispatch process.

5.0 SCHEDULING – DETAILED OVERVIEW

Scheduling is the process of assuring enough generators are connected to the system, at appropriate locations to meet the load forecast, taking into consideration transmission limitations, transmission congestion, and meeting all the expected needs of generation based Ancillary Services so that the system will reliably meet the load.

For the most part, generation scheduling will occur in the day-ahead time frame. However, modifications of the day-ahead schedule may be required in real-time to meet load if there are significant variations of load from the day-ahead forecast or expected generation does not occur.

Each LSE schedules its owned or contracted generators, plus purchases, to meet its forecasted load. All of these schedules are submitted to the SPP RTO for incorporation into the LMP Spot Market.

The following sections describe the information needed by the SPP RTO and the process followed by the SPP RTO for scheduling of generation capacity to meet the needs of the LMP Spot Market given the self-schedules of the market participants. In general, generators submit offers to generate, load submit bids to receive energy from the system[13] and the SPP RTO takes all the information provided to develop a Security Constrained Unit Commitment for the next hour to match resources and load.

5.1 LOAD FORECAST

- SPP RTO develops an hourly (24 hours per day) RTO-wide load forecast for the next day and the following 10 days. Each SPP-RTO Member that has a requirement to serve load

[13] The process of loads submitting bids to receive energy, or curtailing demand are being considered by the CMSWG.

within the LMP Spot Market provides SPP RTO with a forecast of its requirements by 11:00 hours on the day before the Operating Day[14]. Regardless of how the LSE's load is supplied, the each LSE submits the following Operating Day forecast information to SPP RTO:

- Nighttime valley MW
- Morning peak MW
- Afternoon peak MW
- Evening peak MW

In general, the SPP RTO LMP Spot Market forecast takes precedence over the aggregate of the individual SPP-RTO Members' forecasts for the SCUC process.

5.2 LSE AND NON-LSE REQUIREMENTS

This section contains a description of LSE and Non-LSE requirements for the day-ahead scheduling and real-time dispatch periods.

The scheduling responsibilities of a LSE are to:

- Submit forecasts of its customer loads for the next Operating Day.
- Submit economic load management agreements (e.g.interruptible load) to SPP RTO.
- Submit hourly schedule increments for Self-Scheduled LSE Resources to meet LSE customer load. LSEs are not required to submit LSE schedules to match their actual load.
- Submit a forecast of the availability of each LSE Resources for the next seven days.
- Submit Offer Data for LSE Resources for supply of energy to the LMP Spot Market for the next day.
- Submit Bilateral Transactions for delivery within the SPP RTO boundaries if the generation is located inside the SPP RTO boundaries and using existing PTP transmission service, or the generation located outside the SPP RTO boundaries.

LSEs and Non-LSEs may:

- Submit optional requests to purchase specified amounts of energy for each hour of the next day during which it intends to purchase from the LMP Spot Market, along with dispatch rates above which it does not desire to purchase, if desired.
- Purchase transmission capacity reservation in order to receive generation from SPP RTO boundaries if the energy is being delivered to end-users that are located outside the SPP RTO boundaries.

The scheduling responsibilities of LSEs and Non-LSEs may also include:

[14] All scheduling deadlines in this report are subject to change as the CMSWG further develops this market structure.

- Submit schedules for bilateral sales to entities outside the LMP Spot Market from generation within the LMP Spot Market.
- Submit optional offers for the supply of energy, capacity, and other services from Non-LSE Resources for the next operating day only.

5.3 GENERATOR SUBMISSION OF OFFERS

LSE Resources (i.e. designated Capacity Resources) are required to: 1) be self-scheduled to meet their load obligations, 2) offer their output into the LMP Spot Market, or 3) be available to the SPP RTO when called upon by the SPP RTO for reliability reasons using the emergency procedures in Section 7. Non-LSE Resources are not required to be bid into the Spot Market, although it would be in their economic interest to do so. Self-schedules or offers into the LMP Spot Market must be provided to SPP RTO by 11:00 a.m. of the day prior to operation.

Generator offers to the LMP Spot Market will be in three parts: startup, minimum load, and energy from minimum load to full load. Offers for energy must be in the form of monotonically increasing curves. The requirement of three part bids is consistent with the interim market rules developed by the Market Settlement Working Group[15] and is necessary to select units for Operating Reserves as well as for the committing of units as indicated by the SCUC process. Generators may provide offer data to the SPP RTO, which would be a standing offer until changed.

LMP Spot Market receives offers from LSE Resources and Non-LSE Resources. There are general requirements for offer data and specific requirements on market participants.

5.3.1 General Requirements

- Offer Data must be submitted to the SPP RTO by 11:00 a.m. of the day before the Operating Day. Offers received after 11:00 a.m. may not be processed until the following day. Offers received during SPP RTO or NERC holidays will not be processed until the following day. After this deadline, no further offers are accepted for the next day.
- External offers will be made on the basis of an individual generators (resource specific offer).
- A market participant must have title to the power to sell it as LMP Spot Market energy (i.e., no entity can be in the contract path between the SPP RTO Member selling the energy and SPP RTO). The SPP RTO will only accept the schedule if submitted by this market participant.
- SPP RTO does not accept offers where the LMP Spot Market is the source or sink (e.g., SPP-RTO-Market Participant-SPP-RTO).
- SPP RTO does not accept offers for less than one continuous hour.
- A schedule is not accepted without confirmation of the schedule details with all parties.
- External offers are subject to xxxxxxxxxx MW net ramp.

[15] The Market Settlement Working Group was established by the SPP Board of Directors on February 14, 2000 with the responsibility to evaluate, design new processes, request bids, and oversee the implementation of the necessary changes to the wholesale scheduling, settlement, and ancillary services processes necessary to implement retail open access and RTO operations.

The SPP RTO does not accept offers for resources into the LMP Spot Market if that resource is committed to supply another service. SPP RTO does not double count resource capability. For instance, if energy is being offer from a resource to the LMP Spot Market and is already included in the Operating Reserves, the energy can be accepted but the capacity will not participate in Operating Reserves accounting.

Offers not properly submitted are rejected. The SPP-RTO Member is notified of the reason for rejection and the SPP-RTO Member may then take action to submit a new offer.

If offer data for a LSE Resource is not submitted by 11:00 a.m. of the day before the operating day, the SPP RTO uses the offer data and unit availability previously entered into SCUC and considers the data a binding offer.

5.3.2 Offers Submitted More Than One Day In Advance

- Offers may be submitted up to one month in advance.
- This service allows the market participants to turn in schedules to the end of the current month (up to the number of days in the respective month). This service is not meant to be viewed as a rolling 30-day window.
- Offers submitted more than one day in advance received after 11:00 a.m. are not processed until the following day.
- LMP Spot Market offers submitted more than one day in advance are not considered binding until 11:00 a.m. of the day before operations.
- A change to one day of a multi-day offer nullifies the timestamp for the rest the offer. The offer is given a new timestamp and scheduled as though the rest of the schedule was submitted at the time of the change (including ramp room).
- SPP RTO notifies the submitter of the acceptance status of resource specific offers submitted more than one day in advance by 3:00 p.m. of the day before operations or earlier as specified by the submitter.
- No offer is marked as accepted before 11:00 a.m. of the business day before the operating day.
- Offers may be withdrawn before SPP RTO notifies the market participant of offer acceptance and before 3:00 p.m. of the business day before operations, or 11:00 a.m. of the non-business day before operations.

For LMP Spot Market, if a resource schedules a request to change its offer data after a offer has been accepted (e.g., dispatch level, dispatch rate, path) the new offer will be rejected.

Market participants delivering LMP Spot Market energy to the LMP Spot Market submit the following data:

- Identity of all parties that are engaged in the schedule (e.g., buyers, sellers, marketers, transmitters, and brokers).
- Minimum and maximum dispatch levels for each hour.
- Identity of any neighboring market identifiers and priorities, if applicable.

Market participants requesting LMP Spot Market energy from the LMP Spot Market submit the following data:

- Identity of all parties that are engaged in the schedule (e.g., buyers, sellers, marketers, transmitters, and brokers).
- Minimum and maximum dispatch levels in MWs for each hour.
- Dispatch rate in $/MWh above which it does not desire to purchase.
- Identity of any neighboring market identifiers and priorities, if applicable.

This data constitutes a binding offer. Valid offers are entered into the unit commitment analysis.

Offers may be withdrawn before the SPP RTO notifies the market participant of offer acceptance and before 3:00 p.m. of the business day before operations or 11:00 a.m. of the non-business day before operations. All offers for the same period from the same resource of a higher price than the withdrawn offer are also considered withdrawn.

Market participants owning non-LSE Resources report the following data for resource-specific offers, reported on the business day before the next operating day, up to seven days in advance:

- Specific generation resource.
- Minimum and maximum energy for each hour.
- Minimum and maximum generation for each hour.
- Minimum and maximum run times.
- Unit availability for each hour.
- Availability of regulation upper and lower energy limits for each hour.
- Response and constraint data.
- Whether or not to use start-up and no-load fees.
- Time, if any, by which SPP RTO Member requests notification of offer acceptance.

5.4 DEMAND BIDS

It is expected that load will participate in the LMP Spot Market through the provision of Interruptible Demand The form of that participation will depend on the flexibility allowed between LSEs and load entities served by those LSEs, as well as how the market is structured to incorporate offers of interrruptiblity.

5.5 BILATERAL TRANSACTIONS

Bilateral transactions are those generation capacity or energy transaction that use Firm or Non-Firm OATT Point-to-Point (PTP) transmission service through or out of the SPP RTO. Bilateral transactions also include capacity or energy transactions that use Firm or Non-Firm PTP transmission service under existing agreements with transmission owners on the SPP system. Bilateral transactions utilizing the SPP RTO transmission system will be reported to the SPP RTO.

All bilateral schedules using the SPP RTO transmission system must be submitted to SPP RTO.

The SPP RTO confirms the Spot Market Offers with the other market participants that are party to the schedule and with neighboring control areas.

The following information is confirmed with other market participants:

- Energy
- Path
- Dates
- Times
- Confirm energy, path, dates, and times with neighboring control areas.
- Agree on identifiers (tags) for transactions and update identifier (tag) in transaction system.
- Log the priority assigned by the external party or control area.

When the information is confirmed, the status is changed to scheduled and the offer is added to the list of offers already scheduled if the schedule is dispatchable.

SPP RTO will accept schedules only if both of the following conditions are met:

- SPP RTO must be able to confirm the schedule with all parties prior to 2:00 PM day ahead (11:00 a.m. on non-business days). Schedules not confirmed by 2:00 PM (11:00 a.m. on non-business days) will be rejected.
- The SPP RTO makes two attempts to confirm contract information with the other party to the schedule and neighboring control areas. If, after the second attempt to reconcile differences, all parties do not have the same information, the SPP RTO notifies the submitting market participant that the transaction is not confirmed. The submitter of the offer may attempt to reconcile the transaction data with the other parties and resubmit the offer.

After the first failed attempt to confirm the schedule, the following actions are performed:

- The SPP RTO advises the market participant of the discrepancy.
- The market participant can resolve the discrepancy. After 11:00, the offer can not be extended beyond the originally submitted hours or increased above the originally submitted energy value.

After the second attempt to confirm the schedule, the following actions are performed:

- The SPP RTO marks the Bilateral Transaction as unconfirmed.
- The SPP RTO advises the market participant of the discrepancy.
- The market participant can resolve the discrepancy and resubmit the offer.

Changes to schedules for SPP RTO ramps must be submitted by the later of: (a) 60 minutes after SPP RTO notifies the SPP RTO Member of the need to adjust the schedule or (b) 2:00 PM (11:00 a.m. on non-business days).

If the discrepancies are resolved without change to the original bilateral transaction by 2:00 p.m., the schedule status is marked as confirmed. If discrepancies are resolved with changes to original bilateral transaction before the scheduling deadline, the time stamp is updated to the time at which the discrepancies are resolved with the SPP RTO.

Schedules for Firm Point-To-Point Transmission Service must be submitted to the SPP RTO before 11:00 a.m. of the day before the operating day. Schedules submitted after 11:00 a.m. are accommodated, if practicable.

Dispatchable (and must-take) offers are analyzed identically to unit-specific resources. For this reason, dispatchable offers are not permitted to be changed after 11:00 a.m. of the day before operations. This includes changes to path, energy profile and all other offer data.

Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the SPP RTO before 2:00 p.m. of the business day before operations or 11:00 a.m. on non-business days. Schedules submitted after 2:00 p.m. on business days or 11:00 a.m. on non-business days are accommodated if practicable, subject to the following procedures:

- New schedules received from market participants after 2:00 p.m. of the current business day (11:00 on non-business days) or during non-business hours must provide at least 60 minutes notice. If a transaction is reported after 2:00 p.m. of the business day before the operating day or after 11:00 of the non-business day before operations and the transaction uses non-firm transmission, the transaction is curtailed before any other schedules using non-firm transmission.
- If a transaction is reported after 2:00 p.m. of the business day before the operating day, the transaction uses non-firm transmission, congestion is expected on the system, and the transaction might contribute to the congestion, the request for the transaction will not be accepted. These schedules are submitted to the non-business hours facsimile or telephone number provided above.

All bilateral transactions are allowed to be changed with 30-minute notification.

Bilateral transactions not properly submitted are rejected. The market participant is notified of the reason for rejection and the market participant may then take action to resubmit.

Market participants are expected to keep the SPP RTO informed of all bilateral transactions that involve the operation of the SPP RTO LMP Spot Market. The following information is submitted to the SPP RTO:

- Identity of associated transmission service reservation(s) for each hour of the bilateral transaction. Only one transmission service reservation may be applied to one energy schedule in any given hour. Note: two OASIS numbers may not overlap (be used for the same time period) for one schedule.

- A transmission reservation is not required for a LMP Spot Market import where the sink is the same as the interface through which the energy is imported.
- Dispatch rate of the transaction, if it is to be dispatched by the SPP RTO.
- Confirmation from each other SPP RTO Member to the transaction (all SPP RTO Members that are party to the transaction) in addition to the market participant submitting the schedule and the adjacent control area.
- Identity of any neighboring control area identifiers and priorities.

Bilateral transactions scheduled for delivery to native load must be submitted by the market participant that reserved the Transmission Service or the LSE. The LSE ultimately receiving the energy and the market participant that reserved the Transmission Service must both confirm the bilateral transaction. All parties to the transaction must confirm the transaction.

5.6 SPP RTO VALIDATES NEW BILATERAL TRANSACTION SCHEDULE

During validation, the SPP RTO gathers the following information: new bilateral transaction schedule, list of pre-defined valid transaction paths, list of market participants and their roles, and list of valid transaction types, list of scheduled bilateral transactions. The following validation checks are performed:

- Transaction does not already exist.
- Requester is in the list of market participants.
- Start and end date in future.
- Start date before end date.
- Valid transaction path.
- Max. MW > min. MW.
- Valid energy transaction type (firm, non-firm, wheel in, wheel out, Loses).
- Dispatch rate if required.
- If using non-firm transmission, then transaction must be reported to SPP RTO before 2:00 p.m. of the business day or 11:00 a.m. of the non-business day before the operating day.
- If using firm transmission, then transaction must be reported to SPP RTO before 10:00 a.m. of the day before the operating day.
- Effect of new schedule must not violate xxxxxxx MW net ramp rule; scheduled delta interchange over all interfaces + requested Bilateral Transaction does not exceed xxxxx MW.
- If the request for a bilateral transaction is valid, the SPP RTO logs the request and performs the following tasks:
    - assigns transaction identifier used to reference transaction during dispatch
    - time stamps receipt of request
    - marks request status as “valid”

6.0 DISPATCH PROCESS

SPP RTO dispatchers balance load and generation within system reliability limitations by performing real-time security constrained economic dispatch using various tools:

- Electronic dispatch signals are sent to flexible generators to control their output
- Capability to send electronic dispatch signals to each control area for pulsing generators in that control area

- Under transmission constrained conditions:
  - Each generator must receive notice of its nodal price. Individual Generators are sent accepted generation price offers via telephone until such time as the RTO has the infrastructure in place to directly send electronic signals to generators.

The SPP RTO will run a Security Constrained Economic Dispatch (SCED) computer program to develop economic dispatch signals for the units participating in the spot market as well as self-scheduled generators that have submitted offers to the RTO. The Security Constrained Economic Dispatch program will have least cost dispatch as its objective function. The SCED is limited to minimizing the incremental cost of units participating in the SPP RTO spot market. The SCED attempts to dispatch generation such that the total generation output within the SPP RTO will equal the total electric load and transmission losses less net interchange. The SCED also attempts to dispatch generation in such a manner as to respect all applicable security constraints, which include transmission and generation reserve constraints.

The SCED program will run every 14 seconds (every fourth scan cycle) and will result in a price signal or system lambda(s) being sent out to the Control Areas. Thus, the RTO will send an electronic signal to each Control Area every 14 seconds.

6.1 PRICES ARE CONSISTENT WITH DISPATCH

The output of the Security Constrained Economic Dispatch program also serves as an input to the Locational Marginal Pricing Preprocessor (see Figure 3 and the discussion on the LMP Preprocessor below). The generators will be paid nodal prices based on their actual output levels, thus they have an economic interest in following the leading price signals sent out (every fourteen seconds) by the RTO.

6.2 FORMATION OF PRICES

There are a number of both pre and post processing tools that the RTO will use to formulate the locational prices. The tools needed to accomplish this process are depicted in Figure 3 and are listed below:

- State Estimator
- LMP Preprocessor
- LMP Contingency Processor
- LMP Processor

6.3 STATE ESTIMATOR

The State Estimator is a standard power systems operations tool that is designed to provide a complete and consistent model of the conditions that currently exist on the SPP power system based upon metered input and an underlying mathematical model. The State Estimator is used to provide a complete and consistent solution for both the observable and unobservable portions of the electrical network. The output of the state estimator is used in both the Security Constrained Economic Dispatch computer program as well as the Locational Marginal Pricing program.

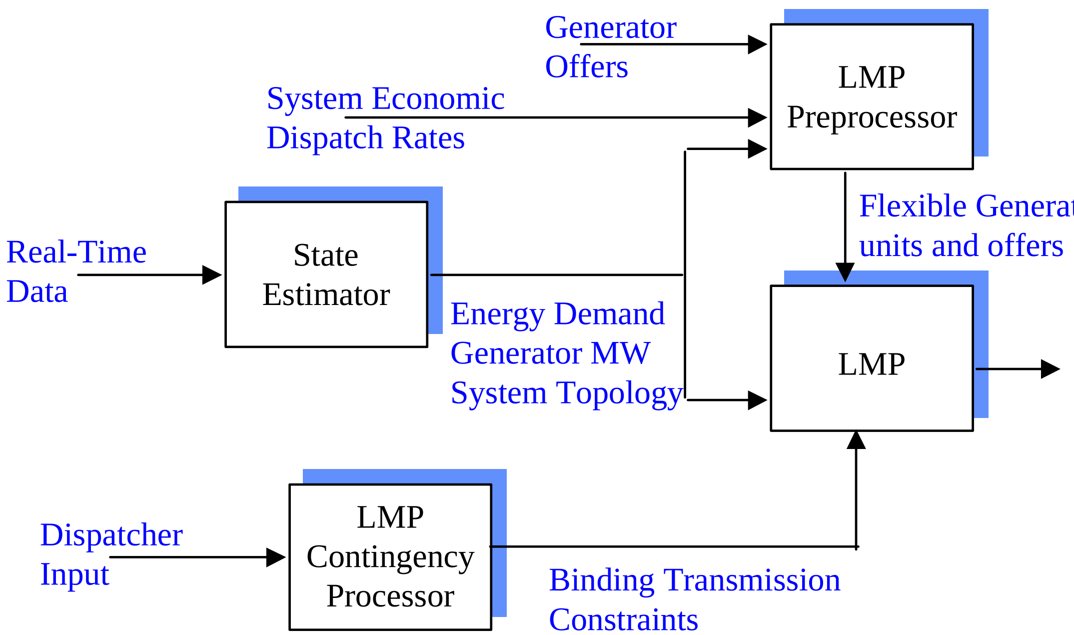


FIGURE 3: Locational Marginal Pricing Model

Data redundancy and the underlying physical and mathematical relationships provide a solution with less error than the original measurements. The State Estimator can correct bad data and calculate missing data in the model. The SPP will need to ensure the current number of observable points on the system are sufficient to provide the accuracy needed in developing nodal pricing as well as load-weights for zonal pricing.

6.4 LMP PREPROCESSOR

In calculating the LMPs, generating units must be "qualified" as a marginal unit – that is, units that are allowed to set the price at their and other buses. This qualification step is the responsibility of the Locational Marginal Pricing Preprocessor (LMPP). The LMPP compares the ideal output of each unit, based on its offer curve and the dispatch signal (last advisory price signal or manual instruction), with its actual output. Units that had an output less than 110% of the ideal MW output for 9 or more of the twelve 5-minute periods of the hour are qualified to set the locational marginal price. Units with output greater than 110% for 4 or more of the twelve five minute periods for the hour are disqualified from setting LMP. Must-run units and energy deployed from Operating Reserve resources are also disqualified from setting the LMP. This qualification step also applies to units serving bilateral transactions that submitted offers into the spot market. Units that are operating at an output level less than the desired setpoint are not subject to explicit penalties. These “under performing” units are paid the LMP for their output and have a lost opportunity cost for the difference between actual output and the ideal output (as suggested by the RTO SCED signal). Additionally, units on bilaterals would be subject to spot energy prices to fulfill bilateral contracts.

With this subset of qualified generators, transmission constraints and system topology data, the LMPs can now be calculated. Units that were disqualified by the LMPP preprocessor become price takers and qualified units get at least the offer price implied by their actual output or the higher LMP set by another qualified unit.

6.5 LMP CONTINGENCY PROCESSOR

The Dispatcher will monitor security limits on a continual basis. When a security limit is about to be reached, the Dispatcher will use the Locational Marginal Pricing Contingency Processor (as depicted in Figure 3) to determine the appropriate action to remedy the constraint. The Locational Marginal Pricing Contingency Processor (LMPCP) provides the operator with solutions to the constraint ranked by cost per MW impact. Remedies may include reconfiguring the grid, redispatch, and curtailing of transactions or dispatchable load. (The system will not go out-of-merit order without Dispatcher input.) If the appropriate Dispatcher action is to run out-of-merit order generation, the result will be that nodal prices will disperse and there will not be a single RTO-wide lambda. As a result, the electronic signals sent to the control areas must be augmented with telephone calls to individual units until such time the RTO has the infrastructure in place to send direct signals to individual generation units.

The LMPCP module may also be used by the SPP RTO Security Coordinator to implement transaction curtailments (NERC TLR procedures) should they become necessary.

The LMPCP module also includes an electronic log, which provides an audit trail to ensure the actions taken by the Dispatcher are consistent with the objective function of least cost dispatch.

6.6 LMP PROCESSOR

Locational Marginal Prices (LMP), Figure 4, will be based on actual total demand and actual total generation as determined by the RTO. The calculated LMPs will be based on the marginal offer cost of dispatching generation (and load) to meet an increment of load at each node on the system, while ensuring that the transmission constraints in and on the boundary of the RTO are not violated. This price may also be expressed as the sum of: (1) the price at a reference bus, (2) a congestion component, which may be positive or negative, and which reflects the difference between transmission congestion costs incurred to meet an increment of load at that bus and transmission congestion costs incurred to meet an increment of load at the reference bus, and (3) a loss component, which reflects the marginal losses at the bus of concern relative to the reference bus. Spot Market prices will not include marginal losses at this time.

The Locational Marginal Pricing Program is an incremental linear programming formulation around the current operating point. The LMP Program is formulated such that the optimal solution will be very close to the current system operating condition. Inputs into the Locational Marginal Pricing Program (LMP block in Figure 3) are the flexible generating units from the LMP Preprocessor, actual generation, load and system topology from the State Estimator, and binding constraints from the LMP Contingency Processor. The LMP Program will run every five (5) minutes and will calculate the nodal prices for all locations. Hub and zonal prices will also be calculated and posted on the RTO website[16]. Zonal prices will be based on load-weighted nodal prices. The load-weights will be determined using 5-minute State Estimator data adjusted for loads selecting nodal pricing.

LMP = Generation Marginal Cost + Transmission Congestion Cost + Cost of Marginal Losses

Figure 4: Cost of marginal losses will not initially be implemented

Hourly LMPs will be determined by quantity weighting the 5-minute prices at each node and will be used for settlements of the real-time spot market. Generators would be settled at their respective nodal LMPs, while loads will have the option of nodal or zonal pricing. The RTO would charge bilateral schedules for any congestion between the points of injection and withdrawal.

6.7 INCLUSION OF MARGINAL LOSSES AND ANCILLARY SERVICES IN NODAL PRICES

The locational marginal prices will not initially include marginal losses or reflect the cost ancillary services. Average losses will be used (as currently implemented in the SPP Tariff) until such time the working group and market participants can further investigate the benefits of charging marginal losses and work through technical implementation issues.

Inclusion of Ancillary Services in locational marginal prices also will require further study and coordination with the Market Settlement Working Group (MSWG).

6.8 SOME CHARACTERISTICS OF LMP NODAL PRICES

- The LMP at a node is the incremental cost to serve one increment of load at that node.
- The LMP at a location is not necessarily equal to the offer of any single generator. It is not the offer of the last generator capacity segment dispatched in a "zone."
- A generator's offer will generally set the LMP at its location when the generator capacity segment is only partially dispatched (unless it is at its minimum, or being held down to provide regulation, spinning reserves, or serve must run requirements).

[16] The RTO website will not be available until implementation of real-time spot market at the end of this year.

- If a generator capacity segment is fully dispatched by the RTO, the LMP that it is paid will be determined by the bids of other generators and will be greater than or equal to the generator's energy bid for that capacity segment.
- If a generator capacity segment is not dispatched, the LMP will be less than its energy offer.
- The LMP can differ between two buses even if a line between them is not at a limit.

6.8 LMP AUDIT AND VERIFICATION PROCEDURES

The SPP LMP calculation will be repeatable and can be audited. All input and output data will be retained for each 5 minute interval. Therefore the LMP calculation for any five-minute interval can be recalculated in an off-line mode.

To ensure that LMP values are accurately calculated and consistent, SPP will run an LMP verification procedure. SPP staff will review dispatcher logs, program error logs and LMP results for each interval of the previous operating day and notify the Settlement group upon verification.

6.9 INFORMATION PROVIDED TO THE MARKET

The SPP RTO website will have an Operational Data page to provide the current five-minute and hourly integrated LMP values for selected points and provide other real-time market information.

LMP values posted will include:

- Selected nodal prices
- Load-weighted zonal average LMPs
- Trading Hub LMPs
- Aggregate LMPs
- Interface LMPs

7.0 EMERGENCY PROCEDURES

Emergency procedures may be needed for a multitude of problems. At this time we will only address generator deficiencies, light load generation emergencies, and transaction curtailments.

7.1 GENERATION DEFICIENCIES

If the SPP RTO determines that the RTO scheduled resources combined with the resources operating on a self-scheduled basis are not sufficient to maintain appropriate reserve levels for the SPP RTO, the SPP RTO will perform the following actions:

- Recalls and dispatches LSE Resources to serve load in the SPP RTO that otherwise would be delivering to loads outside of the RTO.
- Purchases capacity or energy from resources outside of the RTO. The price of this type of off-system purchase will not be considered when determining Locational Marginal

Prices. The cost of purchasing this capacity or energy is allocated to Market Buyers based on a load ratio share for all net short participants.

- Purchases capacity or energy from any resource in the RTO that, for reasons approved by the SPP RTO, have not bid into the LMP Spot Market but are available for use during RTO capacity deficiencies. The price of this type of purchase will not be considered when determining Locational Marginal Prices. The cost of purchasing this capacity or energy is allocated to Market Buyers based on a load ratio share for all net short participants.

As a last resort, the SPP RTO dispatcher will take the following actions:

- Issue public appeal to conserve electricity usage.
- Notify governmental agencies, as applicable.
- Direct Control Areas to implement Load Curtailment programs.

7.2 LIGHT LOAD GENERATION EMERGENCIES

If the SPP RTO determines that the SPP RTO dispatcher can no longer match the decreasing load by reducing the dispatch signal, the RTO will take the following actions:

- Requests all Control Areas to reduce Emergency Reducible Generation (ERG) in proportion to the total amount of ERG reported.
- Attempts to sell Emergency Energy to external systems
- Recommends the shutdown of specific units that are not required for area protection during the current load period or the subsequent on-peak period.

As a last resort, the SPP RTO Dispatcher will take the following actions:

- Require all Control Areas to move regulation from all units and reduce generation to emergency generation levels.
- Require all over-generating Control Areas to reduce their generation by any means to achieve the level requested by the SPP RTO dispatcher.

7.3 TRANSACTION CURTAILMENTS

The SPP RTO will use the NERC Transmission Loading Relief (TLR) procedures to implement transaction curtailments when system conditions warrant their use.

The Dispatcher will use the Contingency Processor and the NERC IDC to determine how much relief is required and to determine which transactions are eligible to be curtailed. The TLR procedures are outlined in the NERC Operating Manual, Policy 9.

Transactions that have selected the “congestion buy-through” option are not subject to TLR curtailments.

8.0 ANCILLARY SERVICES AND THE ROLE OF THE CONTROL AREA OPERATOR

The SPP RTO will consist of multiple Control Areas, which presently reflects the seventeen Control Areas within the Southwest Power Pool. The role of the Control Area operator has evolved over the past few years and will change yet again with the implementation of the SPP RTO. Prior to FERC Order 888, the same entity (e.g. investor-owned utilities, federal agencies, etc.) typically performed both the functions of transmission system security and control area operations, which include the provision of ancillary services. In 1997, the SPP became the Security Coordinator for its member companies, thus separating transmission system security from the various control area functions.

With the issuance of FERC Order 2000 and the resulting implementation of the SPP RTO, the function of the Control Area Operator will change to reflect the need for a regional balancing market and the implementation of a market based congestion management system across the entire RTO. Towards this end, a number of Ancillary Services will transition over to the SPP RTO while some will continue to be provided by the Control Areas. The Table 1 below lists both FERC defined ancillary services supporting transmission and delivery of wholesale energy and other ancillary services under discussion and design for implementation by the SPP RTO MSWG and CMSWG:

TABLE 1: Provision of FERC Defined Ancillary Services

Ancillary Service	**RTO**	**CAO**
#1 Scheduling	✓	✓
#2 Voltage		✓
#3 Regulation		✓
#4 Balancing	✓	
#5 Op Reserves spinning	✓	
#6 Op Reserves supplemental	✓	

RTO = SPP RTO
CAO = Control Area Operator

8.1 SCHEDULING

Scheduling, at least initially, will be done by multiple parties. Not all load in SPP will be under the SPP tariff when the RTO is first formed. Additionally, the Memorandum of Understanding[17]

[17] The "Memorandum of Understanding" between SPP and Entergy approved by the SPP Board of Directors at their July 19-20, 2000 meeting which contained terms and conditions for the development of a contractual attachment to SPP's membership agreement for an independent transmission company (Transco) including Entergy to operate within the structure and under the oversight of the SPP RTO.

between SPP and the Entergy Transco reflects scheduling by both parties depending upon where the transaction sinks.

8.2 REACTIVE SUPPLY AND VOLTAGE SUPPORT

Control Area Operators will establish system voltage control by using controllable reactive sources, including generators, synchronous condensers, and switched capacitors. In conjunction with the use of controllable reactive sources, Load Tap Changing (LTC) transformers will also be used to maintain voltage levels throughout the Control areas.

8.3 REGULATION AND FREQUENCY CONTROL

It is not anticipated that an RTO-wide market for Regulation will be implemented initially within the SPP RTO. Accordingly, individual Control Areas will be responsible for providing regulation service. Thus the Control Areas will be sending out signals to units on Automated Generation Control (AGC) every four seconds. The provision of regulation service will need to be closely coordinated with the RTO as indicated below in the discussion on Net Interchange.

The interaction of the spot market with the provision of Regulation Service in small Control Areas warrants further study.

8.4 OPERATING AND SPINNING RESERVES

The interim Market Rules[18] as developed by the Market Settlement Working Group do not provide for an RTO-wide market for Operating and Spinning Reserves on day one of RTO operations. The CMSWG rules also will not include a separate market for Operating Reserves when the congestion management system is initially placed in-service, The RTO will use the offer date supplied by Resources offering into the Spot Market to select units for Operating Reserves. The RTO considers the minimum-run and startup costs when selecting units to provide Operating Reserves to minimize capacity payments. The capacity payments for Operating Reserves are the responsibility of Load Serving Entities and are allocated to LSEs based on a load ratio share basis.

8.5 TIME ERROR CORRECTION

The system-wide mismatch between load and generation results in frequency deviations from scheduled frequency. The integrated deviation appears as a departure from correct time, i.e. as a time error. Time Error correction actions will be coordinated by the RTO, but will be implemented by the individual Control Area Operators.

[18] The interim Market Rules are being developed by both the CMSWG and the MSWG for implementation at the end of this year. These interim Market Rules will be changes as approved by the SPP Board of Directors as necessary to obtain enhanced energy market operation and performance.

8.6 OTHER ANCILLARY SERVICES

There are other Ancillary Services, such as Black Start Service, that will need to be coordinated within the SPP RTO but may be provided at the control area level. This document will only address the necessary coordination between the RTO and the Control Areas that are necessary for the provision of an RTO coordinated spot balancing market and the resulting dispatch. The Market Settlement Working Group (MSWG) has been vested the authority to determine the procedures under which the remaining Ancillary Services will be provided.

8.7 DESIRED NET INTERCHANGE

The RTO will send a net interchange schedule to each Control Area every five (5) minutes for use in managing the Area Control Error. The net interchange schedule will be based upon the dispatch signals generated by the Security Constrained Economic Dispatch program, transmission schedules submitted by Market Participants, and the expected forecast of load for the following five minute period. Schedules between SPP Control Areas will not require a NERC tag while schedules with external Control Areas will require NERC tags. The impact on adjacent systems of not tagging transactions within the SPP RTO needs to be considered when addressing seams issues between neighboring RTO's and Control Areas.

The individual Control Areas will continue to manage the Area Control Error and be subject to NERC control performance and disturbance standards. Accordingly, each Control Area will be responsible for providing regulation service and sending out control signals for regulation to units on Automated Generator Control (AGC).

9.0 INTERACTION OF MARKETS

This Paper lays the foundation for the development of a Real-Time Locational Marginal Price Spot Market that accounts for the management of transmission congestion. These rules for the LMP Spot Market will be implemented under the Pro Forma tariff Ancillary Service Schedule 4 – Energy Imbalance Service. At this time it is expected the LMP Spot Market will be the first open bid market operated within SPP RTO.

It is expected that markets for other services, including other Pro Forma Ancillary Services, will be developed in the future. Rules developed for one market could have significant adverse effects on other markets. It is vital that all markets within SPP RTO have rules and be implemented such that they do not interfere with each other. Therefore, any market implemented by SPP RTO and the rules associated with the provision of and settlement for any Pro Forma Ancillary Service even without a market must be closely coordinated with the CMSWG and have the approval of the Commercial Practices Committee or its designee.

APPENDIX A - DEFINITIONS

Term	Definition
Access Charge	Charges paid by transmission users designed to recover the revenue requirements of the transmission owners.
Ancillary Services	As defined in SPP FERC approved Open Access Transmission Tariff
Area Control Error (ACE)	The instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including a correction for meter error.
Automated Generator Control (AGC)	Equipment that automatically adjusts a Control Area’s generators from a central location to maintain its interchange schedule plus frequency bias
Balanced Schedules	Schedules that exactly match generation to delivery quantity.
Bilateral Market	Market where services/products are bought and sold between two parties.
Bilateral Transactions	Those generation capacity or energy transaction that use Firm or Non-Firm OATT Point-to-Point (PTP) transmission service through or out of the SPP RTO. Bilateral transactions also include capacity or energy transactions that use Firm or Non-Firm PTP transmission service under existing agreements with transmission owners on the SPP system. Bilateral transactions utilizing the SPP RTO transmission system will be reported to the SPP RTO.
Black Start Service	Following the complete loss of system generation (blackout), it will be necessary to establish initial generation that can supply electric power to begin system restoration. Generators capable of self-starting without any source of off-site electric power and maintain adequate voltage and frequency while energizing isolated transmission facilities can supply this service.
Bus	An injection or withdrawal point on the transmission system.
Capacity payment	Payment to a Market Participant who provide generation resources to the SPP RTO market for spinning reserves, startup and minimum run costs and other ancillary services as needed.
Capacity Resource	Resources or Units selected by LSEs to serve as Network Resources (including Planning Reserves or Installed Capacity Resources). See LSE Resource definition.
Congestion Buy Through	The practice of allowing participants with bilateral transactions to pay the locational difference in price between the point of injection and the point of withdrawal (of their transaction) rather than being curtailed.
Congestion Costs	The incremental cost of delivering energy from a designated point of receipt on the transmission system and designated point of delivery on the transmission system.
Control Area (CA)	An electric system or systems bounded by interconnection

	metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. (NERC)
Controllable Reactive Sources	Any of an assortment of electrical devices connected to the transmission system under the direct or indirect control of the Control Area Operator such as synchronous generators, synchronous condensers, static var compensators, series and shunt capacitors and inductive reactors.
Covered Schedules	Schedules that have explicit transmission rights.
Generator Offer Data	Generator unit specific data need for consideration in the LMP Spot Market. A 3-part offer contains separate entries for startup, minimum generation costs and energy above minimum generation.
Installed Capacity	Generating capacity owned or under contract to meet load plus a planning reserve margin. SPP currently has a 12% planning reserve margin.
LMP Spot Market	Real-time energy market established to coordinate real-time generation dispatch to ensure reliable and secure energy delivery in order to avoid power system stability, voltage support and transmission congestion problems.
Load Serving Entities (LSEs)	LSEs are responsible for making arrangements to serve its load, which for this Paper we will limit to load forecast and resource requirements.
Load Tap Changing Transformer (LTC Transformer)	A transformer equipped with a device (a tap changer) capable of changing the tapes (changes voltage) while the transformer is in operation (avoids an outage of the connected load).
Locational Marginal Price (LMP)	The marginal price to provide an increment of energy at that location.
LSE Resources	LSE Resources are those owned or under contract generator identified by LSEs to serve load. LSE Resources are required to be self-scheduled, offered into the LMP Spot Market or otherwise available to the SPP RTO for emergency operations.
Market Participants	Buyers and sellers of services and products.
Must Run (RMR)	Generators required to run regardless of economic merit or pre-existing delivery obligations. A generator is typically designated RMR for power system stability, voltage support and/or transmission congestion problems associated with serving load.
Nodes	A node is a point on the transmission network where generator(s) and/or load(s) are connected. Nodes are commonly known as bus or station, but are not necessarily the same.

Nodes and Zones and the Calculation of zonal prices for loads	In nodal pricing, bids are used to define the marginal cost of serving load at each location. In zonal pricing, areas are aggregated into zones in which nodal prices are anticipated to be similar. Under zonal pricing, the price for the zone is used to settle imbalances. In all open markets, some form of averaging is used to charge most loads. The averaging of nodal prices are driven by metering limitations and the desire to protect smaller end-use customers. Some issues: Zonal prices assume that there is no significant congestion within each zone to cause locational prices to be different within the zone. That congestion can be accurately predicted that occurs frequently and is the most costly.
Non-Firm Point-to-Point Transmission Service	Transmission service provided under the SPP Regional Tariff that is reserved and scheduled on an as-available between Points of Receipt and Delivery pursuant to Part II of the Tariff.
Non-LSEs	SPP RTO approved market participants that are not LSEs.
Non-LSE Resources	Non-LSE Resources are generators that have not contracted with LSEs to serve load on the SPP transmission system.
OATT	Open Access Transmission Tariff, is the Tariff approved by the Federal Energy Regulatory Commission ("FERC") complying with FERC Order 888 and 889 providing nondiscriminatory transmission service.
Operating Day	Day of actual operation to meet real-time load, starting at midnight continuing through the day to the following midnight.
Operating Reserves	The capability above firm system demand required to provide for regulation, load forecast error, equipment forced and scheduled outages and local area protection. Operating Reserves consisting of spinning and non-spinning reserves.
Operational Data Page	Website controlled by SPP RTO that contains operational data for viewing by all market participants.
Price Taker	A resource willing to take the market price for its service.
Price-offer curve	An offering by a Market Participant to the SPP RTO comprising monotonically increasing values representing their offer of price per megawatt generated.
PTP	Point-to-Point
Ramp or Ramp Rates	The rate at which a generating unit can change it's output. Limitations on the movement of generation can limit the change in transactions or schedules.
Security Constrained Economic Dispatch (SCED)	The real time economic dispatch of generation to meet load, constrained to meet security and reliability requirements based on potential power system stability, voltage support and transmission congestion problems associated with serving that load.

Security Coordinator	An entity that provides the security assessment and emergency operations coordination for a group of Control Areas. Security Coordinators shall not participate in the wholesale or retail merchant functions.
Self scheduling	The practice of market participants scheduling their own generation or load to meet their obligations.
Self-Scheduled LSE Resources	LSE Resources scheduled by the LSE to meet at least part of its load obligations.
Spot Market	Market that provide a real-time price of service/product.
Spot Market Offer	The offer of generation resources into the real-time spot energy market made by a Market Participant for consideration and possible use by the SPP RTO through its security constrained economic dispatch process.
SPP RTO	FERC approved Southwest Power Pool Regional Transmission Organization.
State Estimator	State Estimator to estimate the load at every modeled bus. A State Estimator is a computer program used to provide a complete and consistent solution in near real time for both the measured and non-measured parameters of the electrical network.
Switched Capacitor	A capacitor bank which can be switched into or out-of operation in multiple step as compared to an all-in or out of operation scenario.
Synchronous Condenser	A synchronous motor without a connected mechanical load capable of producing or consuming vars to provide dynamic support, stability and reliability.
Var	Volt-amperes reactive or apparent power, the reactive component of power which is 90 degrees out of phase with the “real” power component.
Voltage Control	Employed to maintain reliability and dynamic stability on the transmission system primarily utilizing static and dynamic var resources deployed by the Control Area Operator.
Zones	A zone is a combination of nodes (based upon the 5-minute State Estimator load weighted average nodal prices within the zone).

APPENDIX B - DESCRIPTION OF THE UNIT COMMITMENT PROCESS

In this design element, we propose that the RTO offer a voluntary unit commitment service, in conjunction with its bid-based short-run markets. The service would be offered to generators as a way to optimize the economics of each generator's commitment to start up and/or be available for immediate operation during the dispatch day. Prominent features of the unit commitment service include:

- The unit commitment service would be voluntary. Generators that preferred to self schedule their units – i.e., make their own decisions about when to start up their units -- would be free to do so. Generators that preferred to have the RTO optimize their units' commitment based on economic and physical operating parameters supplied to the RTO would have that option.

- The RTO unit commitment service would be driven by the submission of three-part bids by each generator choosing to use the service. Along with various physical attributes of each unit – bus location, capacity, start-up requirements, minimum operating level, ramping rates and so on – each bidder would provide the following price information:

    - The unit's start-up costs.
    - The unit's minimum operating costs.
    - The unit's incremental running costs at each level of output (could be a series of blocks at each level with corresponding prices or a unit supply curve).

- The three-part bids would be submitted in the day-ahead time period. The requirement to submit these bids well ahead of real-time would allow the RTO to determine which units to commit in advance and allow sufficient time for operators to start their units and bring them up to at least minimum operating levels.

- Units committed by the RTO and actually dispatched would be compensated for their energy production at the LMP-based market-clearing prices determined by the RTO.

- Generators participating in the unit commitment process would not be financially penalized for their participation. To the extent that units committed by the RTO were not dispatched for a sufficient number of hours to recover their start-up and minimum operating costs from the prices they received in the energy and/or reserve markets, they would be made whole by additional payments above the revenues they received in the energy and/or reserve markets. On the other hand, if the market payments were sufficient to cover these additional costs (as well as the bid-in running costs), no further payments would be made. It is anticipated that these make-whole payments would be minimal in that only the marginal units typically would run the risk of not recovering the start-up and minimum operation costs.

- The costs incurred by the RTO in such make-whole payments would be recovered from market participants through an uplift charge.

An important rationale for an RTO-optimized unit commitment service is that it mitigates some of the risks generators face in making bids into a bid-based market and can thus lead to a more efficient dispatch. Different generators have different start-up and minimum generation costs, as well as varying running costs. If each generator can submit only a single part bid, the price it bids must reflect all of these costs. However, a generator unsure of the number of hours it might be dispatched, given its bid, would be uncertain how best to reflect its start-up and minimum generation costs in a single bid price. For example:

- If the generator included it's start-up and minimum generation costs in the total bid for the first hour of desired operation, it might risk not being dispatched, because this total bid price would be too high.

- If the generator spread its start-up and minimum generation costs over several hours of the dispatch, it might risk being dispatched for fewer hours and thus not recovering its total costs during the hours in which it was dispatched.

- If it did not reflect its start-up and minimum generation costs at all in its bids, in order to enhance its chances of being selected for the dispatch, it would risk not recovering these costs if the market prices it received for the hours it operated were not sufficient to recover them and its running costs.

By reducing this risk, an RTO-optimized unit commitment service allows generators to bid their marginal running costs, rather than adjust their bids to reflect the start-up and minimum generation costs in ways that would not be apparent to the RTO. With the additional information, the RTO can arrange a more efficient (economic) dispatch. The RTO takes the start-up and minimum generation costs into account, along with each unit's incremental running costs, and optimizes the dispatch to minimize the total bid-in cost for the security-constrained dispatch. In optimizing the unit commitment, the RTO ensures each generator that it will either (a) receive sufficient market revenues for its energy and/or reserves to cover all its bid-in costs or (b) be made whole for any deficiency between its total bid-in costs for the period it was dispatched and the revenues it receives from the market.

SECURING ADEQUATE SUPPLIES IN REAL TIME

In the market design being developed for the SPP RTO, an important principle is to allow market participants maximum flexibility in arranging their commercial transactions, subject to the need to ensure reliable operations. The unit-commitment process is one measure the RTO can use to ensure that sufficient units are committed to be operating and/or available for quick response to cover the loads forecast by the RTO, while leaving market participants more flexibility in scheduling their loads and generation with the RTO.

For example, the market design can allow parties to schedule their expected transactions day-ahead while also allowing parties the flexibility to use the RTO's real-time spot market to cover any unscheduled load or generation. The following process illustrates this concept:

- Day ahead, parties submit their expected forecasts for the dispatch day, their proposed schedules and their various bids for the RTO's use in balancing the market and redispatching (if needed) to resolve congestion
- The RTO considers the forecasts of load, the scheduled load and the bid-in load. Based on its *independent forecast* of loads for the dispatch day, the RTO then determines the amount of additional resources, if any, that may need to be committed to meet the total load forecast for the dispatch day
- In arranging the real-time dispatch, the RTO will optimize the dispatch in two steps:
  - In the first step, the RTO will optimize the dispatch using all three portions of the three-part bids. This dispatch will be optimized to meet the bid-in load at the lowest as-bid cost. All units chosen from this optimization will be committed.
  - In the second step, the RTO will optimize the dispatch to meet the remaining forecast load – the additional load expected by the RTO above the bid-in and scheduled load. However, units selected to meet this extra load will be chosen based only on their start-up and minimum generation costs. These units will also be committed, but they may or may not be dispatched in real time, depending on how much (if any) of the extra load forecast by the RTO actually materializes in real time.

RATIONALE BEHIND THE TWO-STEP OPTIMIZATION

The effect of the two-step optimization is to provide the lowest cost dispatch for any loads that submit bids in advance, while minimizing the commitment costs for any extra units that must be committed to meet loads that do not schedule or bid in advance. If only the scheduled and bid in loads materialize, the RTO will have minimized the commitment costs for the extra units that are not needed. If the extra load forecast by the RTO actually materializes in real time, the RTO will have committed sufficient units to meet that load reliably.

However, since the commitment of "extra" units does not consider each unit's incremental running costs, it is likely that if these units are required to meet the extra load, their running costs will be higher than units that would have been committed if all of the load had scheduled or submitted bids in advance. The net result is that the real-time market prices may tend to be somewhat higher if a significant amount of load appears only at the last moment and does not schedule or submit bids in advance.

EXAMPLES OF UNIT-COMMITMENT IN OTHER MARKETS

The proposal described here is essentially the same as that used in the PJM market. A similar, but not totally identical process is used in the New York market. A unit commitment service using three-part bids is also being developed for the ISO-New England market. *There is no ISO-coordinated unit commitment service in California. The absence of this feature is a principal reason why the ISO has had problems with so-called "underscheduling" in the ISO's day-ahead market*. Various rules encourage such underscheduling, but without a unit commitment service to ensure sufficient resources are available in the event that additional loads not scheduled day-ahead show up in real time, the ISO there is considering the use of severe penalties to discourage parties from relying on the real-time spot market. The development of a unit commitment service is a means to ensure reliability without artificially restricting or penalizing use of the real-time spot market.

8.0 CONTROL AREA CERTIFICATION

An entity seeking to be recognized as a Control Area operating within SPP must be a member of SPP and must attain and maintain Control Area certification. Control Area certification will be performed by SPP pursuant to NERC approved Control Area Criteria and certification procedures to be developed and maintained by the Security Working Group. These certification procedures will be publicly available by posting on the SPP home page.

SPP Control Area Criteria and Certification Procedures V1.0

I. NERC Control Area Criteria

Criteria Subsections

A. Confirmation as a Control Area
B. Criteria

Introduction

These Criteria establish the requirements for consideration as a NERC CONTROL AREA. They are based on existing NERC Operating Policies and Standards.

A. Confirmation as a Control Area

1. **Confirmation by Southwest Power Pool.** To be recognized as a NERC-Certified CONTROL AREA, the entity must be reviewed and confirmed by SPP. The entity must be a member of SPP and meet and follow all of these requirements.

B. Criteria For A Control Area

NERC Criteria

1. **Generation.** The CONTROL AREA shall operate generation or have the necessary contracts to operate generation to:

1.1. Meet its area instantaneous demand, INTERCHANGE SCHEDULE, OPERATING RESERVE, and Reactive resource requirements.

1.2. Provide its frequency bias obligations.

1.3. Balance its NET ACTUAL INTERCHANGE and NET SCHEDULED INTERCHANGE

1.4. Use tie-line bias control (unless doing so would be adverse to system or the INTERCONNECTION reliability).

1.5. Comply with Control Performance and Disturbance Control Standards **(see Policy 1E, "Generation Control and Performance – Performance Standard")**

1.6. Repay its INADVERTENT INTERCHANGE balance. **(see Policy 1F, "Generation Control and Performance – Inadvertent Interchange")**

2. **Metering.** The CONTROL AREA shall have meters on all tie lines with adjacent CONTROL AREAS to record actual interchange (MW and MWH) in real time. INTERCHANGE meters shall be at a location common to both CONTROL AREAS, and shall provide identical values with opposite signs to both CONTROL AREAS.

3. **Communications.** Shall provide adequate and reliable communication facilities to assure the exchange of information necessary to maintain Interconnection reliability.

4. **Transmission arrangements.** Shall have appropriate transmission arrangements (through ownership or contracts) to meet its generation or load obligations.

5. **System operators.** Shall be operated by NERC-certified system operators 24 hours per day, seven days per week.

6. **E-tag services.** Shall provide E-Tag Tag Authority and Tag Approval services. (Eastern and Western Interconnections)

7. **Performance surveys.** Shall comply with performance survey requirements. **(see Policy 1G, "Generation Control and Performance – Control Surveys")**

8. **Back-up Control Center.** Shall provide a plan to continue operation in the event its control center becomes inoperable.

9. **Coordination.** Shall coordinate maintenance and protective relaying, with other systems and the Security Coordinator, that may affect reliability.

10. **System Restoration.** Shall have a restoration plan to reestablish its electric system and cover emergency conditions.

11. **Compliance with NERC Operating Policies and Standards.** Shall have knowledge of and comply with all NERC approved Policies and Standards as currently posted.

SPP Criteria

1. A Control Area must be a member of SPP and adhere to all of SPP's Criteria.

2. A Control Area shall share operating data in accordance to SPP Criteria 5.1.

3. A Control Area shall notify the Security Coordinator of an operating condition that may adversly affect reliability, coordinate scheduled transmission outages and meet other requirements in accordance to SPP Criteria 5.2.

4. A Control Area must be a participant in SPP's Operating Reserve Program as defined by SPP Criteria 6.6.1 and in accordance to SPP Criteria 6.0.

5. A Control Area must have automatic under frequency relaying to curtail load in accordance to SPP Criteria 7.3.

6. A Control Area shall reduce their area load during a generation deficiency until the available generation is sufficient to match their area load, in accordance to SPP Criteria 7.3.

7. A Control Area shall have a detailed black start plan and train personnel in its implementation in accordance to SPP Criteria 9.0. The plan shall be on file at the SPP office.

8. A Control Area shall have a satellite phone that meets the SPP emergency communication requirements under SPP Criteria 10.0.

9. A Control Area shall participate in SPP's Transmission Line Loading Relief Procedures.

II. Control Area Certification Procedures

Background

To be recognized as a NERC control area the NERC Operating Committee requires that an entity seeking recognition as a control area be certified by the Region where the entity proposes to operate. This describes the process by which an entity can be certified by SPP as a control area. The SPP Board of Directors shall have the sole authority for certifying a control area in SPP.

Any entity that desires to operate within SPP as a control area must be an SPP member and must attain and maintain SPP control area certification. All generation, transmission, and load within the metered boundaries of an SPP-Certified Control Area shall meet and follow all SPP Criteria.

Certification Process

The primary steps in the Control Area Certification Procedure, and the entity responsible for each step, are as follows:

1.	Process Initiation –	Entity seeking certification the “Applicant”
2.	Provision of criteria, process, documentation, etc. –	NERC and SPP
3.	Formation of Certification Review Team –	SPP
4.	Data collection –	SPP
5.	Data review –	SPP Review Team
6.	Site visit –	SPP (Review Team)
7.	Recommendation –	SPP (Review Team)
8.	Certification –	SPP
9.	Notification and Operations Authorization –	NERC

While not specifically referenced in this document, as with all NERC Standards, SPP’s specific requirements and guidelines are used in conjunction with (but not in place of) the NERC Control

Area Certification Procedure. The Certification Process shall be completed in a maximum allowable time of six months from the initiation of the process.

Control Area Certification Procedure

1. Any entity seeking certification as a Control Area (the "Applicant") will initiate the certification process by making a formal request to the NERC Office.

2. NERC will notify all appropriate and involved parties and provide each with the necessary information regarding Control Area certification, the certification process, and the duties expected from each entity.

3. If the Applicant's area of operation is within SPP, SPP will be notified by NERC and will be responsible for conducting the formal review process and determining and awarding certification.

4. The Applicant and SPP shall agree to a time schedule to complete the certification process including specific milestones and a certification date. The SPP Control Area Certification Procedure and certification recommendation shall be completed within six months of the date when the initial request was received by NERC.

5. SPP will provide forms and questionnaires that will be used by all entities involved in the Procedure. These forms and questionnaires will be used to address the Applicant's capabilities and actions as they relate to previously established Control Area requirements. The following list of entities will be recipients of the questionnaires as each is a source of necessary certification information and data:

    - Applicant (i.e. entity seeking Control Area certification)
    - Control Areas physically interconnected with the Applicant
    - SPP Security Coordinator

6. SPP will provide its expectations and standards regarding confidentiality and retention of all data reporting, completed questionnaires and forms, and reports and recommendations associated with the documentation it provides and receives.

7. SPP will select and assemble a balanced Certification Review Team to be charged with the responsibility of determining if the Applicant meets NERC and SPP Control Area Criteria. The Review Team will typically consist of the following:

- SPP Engineering and Operating Committee member (Review Team chair)
- SPP Security Working Group member
- SPP Transmission Assessment Working Group member
- SPP Commercial Practices Committee member
- SPP Security Coordinator
- Representative from NERC
- Representative from another NERC region

8. All Review Team members will be agreed to by the Applicant and SPP, and will subject themselves to confidentiality agreements for any data that is made available to them through the certification review process.

9. The Review Team will formulate its certification decision based strictly on data collected from the questionnaires and from observations and information collected during an on-site visit to the Applicant's facility. The Review Team's recommendation will be supported by the production of a compliance evaluation review form and a formal report.

10. The Review Team will conduct at least one on-site visit to the Applicant's control center facility. During the visit, Review Team members will:
    - Review with the Applicant the data collected through the questionnaires,
    - Interview the Applicant's operations and management personnel,
    - Inspect the Applicant's facilities and equipment, and
    - Review all necessary documents and data.

11. The Review Team will conclude its initial findings with a report to the Applicant and to the SPP Board containing a recommendation to certify or withhold certification. If the recommendation is to withhold certification, specific areas of deficiency, corrective action items, and a timetable for performing these corrections must be identified and communicated.

12. The Review Team will re-evaluate the Applicant in the deficient areas if the corrective actions occur within the timetable. The Review Team will be responsible for any follow-up work that is needed and continue such work until a "certify/deny" decision is made.

13. The SPP Board will consider the Review Team's recommendation and approve or disapprove the recommendation.

14. When the SPP Board of Directors grants certification status to the Applicant, SPP Staff will notify the Applicant and NERC.

15. Upon receiving notification from SPP that the Applicant has been certified as a Control Area, NERC will notify all of the necessary entities and authorize the Applicant to begin its Control Area operations. Control Area operations shall not begin or continue without this NERC authorization.

III. SPP Questions to be Included in Questionnaires

Compliance and Evaluation

- Does the Applicant's EMS/SCADA system have the capability to supply operating data to SPP as required in Criteria 5.1?
- The Applicant has an ARS terminal installed and personnel trained in its use?
- The Applicant has established procedures in place to meet all reporting requirements.
- Does the Applicant have procedures in place to coordinate scheduled transmission outages with the SPP Security Coordinator?
- Does the Applicant have automatic under-frequency relaying installed to meet SPP Criteria?
- Does the Applicant have documentation showing the operating frequency level for the under-frequency relaying?
- Does the Applicant have documentation showing the amount of load to be curtailed for each operating frequency?
- Does the Applicant have procedures in place to curtail load during generation deficiencies?
- Does the Applicant have a black start plan on file with SPP?
- Is its personnel trained in its implementation?
- Does the Applicant have a satellite phone for SPP's emergency communications?
- Does the Applicant have procedures in place to participate in SPP's Transmission Line Loading Relief (TLR)?
- Is the Applicant connected to the SPP frame relay network and have terminal equipment in place?
- Does the Applicant understand SPP's Criteria?
- Has the Applicant completed the Applicant Questionnaire?

Adjacent Control Areas

- Has the Applicant coordinated emergency operating plans with you?

Security Coordinator

- Is the Applicant able to meet all reporting requirements?
- Has the Applicant's data been established in the ARS?
- Has the Applicant's system been modeled in SPP's network model and linked to their ICCP data?
- Has SPP received the ICCP data from the Applicant?
- Has the Applicant demonstrated the ability to communicate with SPP by satellite phone?
- Does the Applicant have a black start plan on file?

SPP Region

- Is the Applicant a member and signed the membership agreement?

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

BOARD OF TRUSTEES MEETING

October 12–13, 2000
Naples, Florida

HIGHLIGHTS OF THE MEETING

NERC/NAERO Transition — Moving forward with the transition of NERC to NAERO in advance of federal legislation, the Board approved the formation of three new Board-level task groups — Governance, Funding, and Compliance — to develop specific recommendations for consideration at the February 2001 meeting.

- **Governance** — To recommend the details of how governance could be turned over to the NERC independent Trustees with a stakeholders committee available to provide advice and recommendations.
- **Funding** — To consider a new funding model for NERC that would incorporate the concept of user fees.
- **Compliance** — To recommend a contract-based model in which Regional Councils enforce compliance with selected NERC and Regional standards, including the imposition of monetary penalties and other sanctions. NERC would have responsibility for oversight, coordination, and assessment of effectiveness of the Regional programs.

2001 NERC Budget — Approved the 2001 Budget of $11,600,825 and Regional Assessments of $12,513,096. The Board agreed that any additional or Pending Projects would require Board approval and would be funded out of the Fund Balance. A new Cost/Benefit Analysis and Allocation Task Force will be established to bring proposed projects to the Board for approval.

New Reliability Model — The Board acknowledged the ongoing progress of the Control Area Criteria Task Force in developing a new Reliability Model and asked the Task Force to come back in February 2001 with recommendations for dealing with "independence" as it relates to the Model.

Market-Reliability Interface Collaborative Planning Initiative — Approved the following Executive Team recommendations:

- Accept the Market-Reliability Interface Collaborative Planning Initiative report, and
- Direct the Executive Team to recommend at the February 2001 NERC Board meeting immediate actions that NERC should take as a result of the report.

On a related matter, Board Chairman Gary Neale asked the Market Interface Committee to take the lead, with support from the Operating and Planning Committees, in evaluating the reliability implications of RTO filings.

Security Coordinator Standards of Conduct — Approved the Security Coordinator Standards of Conduct. Eighteen of the twenty-one Security Coordinators had signed by the time of the Board meeting; the remaining signatures were reported to be forthcoming.

Operating Standards — Approved proposed changes to four Operating Appendixes that had been in effect on an interim basis: Appendix 3A1 "Tag Submission and Response Timetables," Appendix 3A2 "Tagging Across Interconnection Boundaries," Appendix 3A3 "Electronic Tagging Service Failure Procedures," and Appendix 3D "Transaction Tag Actions." The approved Appendixes are posted at ftp://www.nerc.com/pub/sys/all_updl/oc/opman/opman.pdf.

Electronic Scheduling — Received a status report on the effort to date by the Electronic Scheduling Collaborative to develop an industry-wide response to the FERC ANOPR on Electronic Scheduling.

Reliability Assessment 2000–2009 Report — Approved the *Reliability Assessment 2000–2009* report, subject to final comments by Board members by October 23, 2000. The Executive Committee, on behalf of the entire Board, will review the edited report for final approval of publication, which is expected on or about November 1.

Standing Committees — Changed the name of the Adequacy Committee to the Planning Committee; approved replacement representatives on the Standing Committees; and changed the terms of office for the standing committees from one to two years, beginning July 2001.

Future Meetings — Approved changing the location of the October 15–16, 2001 meeting from San Diego, California to New Orleans, Louisiana.