Southwest Power Pool

BOARD OF DIRECTORS MEETING and SPECIAL MEETING OF MEMBERS

July 27, 2004

Embassy Suites, KCI – Kansas City, MO

• A G E N D A •

10 a.m. – 3 p.m. CDT

Board of Directors Meeting

1. Administrative Items .... Mr. Jim Eckelberger
2. President's Report...Mr. Nick Brown
3. Regional State Committee Report...Ms. Denise Bode
4. Strategic Planning Committee Report .... Mr. Richard Spring
5. Markets and Operations Policy Committee Report .... Mr. Mel Perkins
6. Finance Committee Report .... Mr. Harry Skilton
7. Human Resources Committee Report .... Mr. Quentin Jackson

Adjourn for Special Meeting of Members

Special Meeting of Members

1. Strategic Planning Committee Report .... Mr. Richard Spring
    a. Vote to Waive 30-day Notice Requirement
    b. Bylaws Revisions

Reconvene Board of Directors- Executive Session

Southwest Power Pool
BOARD OF DIRECTORS MEETING
Weston Oklahoma City
April 27, 2004

- Summary of Action Items -

1. Approved minutes of the March 16, 2004 meeting.

2. Approved the Strategic Planning Committee's recommendations to conduct a coordinated cost-benefit study in lieu of each jurisdictional Member proceeding independently, and the sharing of the cost of this effort by all SPP Members.

3. Approved the Independent Market Monitor Selection Task Force's recommendation to select Boston Pacific as the Independent Market Monitor and direct SPP staff to develop and execute a contract.

4. Approved the Operations Policy Committee's recommendation for changes in SPP Criteria 2 to clarify criteria concerning adequate capacity.

5. Approved modifications to Tariff Part IV including addition of Section 39 to clarify SPP as the sole transmission provider.

6. Approved modifications to Tariff Attachment O to provide SPP with the authority to independently oversee the regional transmission plan and solely determine the priority of transmission planning projects.

7. Approved modifications to Tariff Attachment P to change the non-firm hourly "No Later Than" Energy Scheduling deadline from 1500 day prior to 20 minutes prior to the hour.

8. Approved the addition of new Tariff Attachment Z to allow SPP to implement a process that allows aggregation of multiple requests received during a specified time frame into a single study.

9. Approved the new Tariff Attachment AA for transmission customers to have the optional ability to prepay for transmission service.

10. Approved modifications to Service Schedule 4-A to:
    1. Clarify that Schedule 4-A would only apply to transactions across Control Area boundaries;
    2. Provide a default basis for allocation of generation output among multiple schedules from a single generator where the generation operator fails to provide a timely basis for settlement;
    3. Set a reasonableness standard for acceptance of other arrangements as alternatives to Schedule 4-A; and
    4. Establish a new pricing basis for the charges under Schedule 4-A, replacing the use of the individual Transmission Owner's FERC approved Schedule 4 rates.

11. Approved the slate of nominees for the Members Committee to become effective May 1, 2004.

12. Approved the Finance Working Group's recommendation for a scope statement as the charter of the Finance Committee.

13. Approved a resolution for Mr. Al Strecker in honor of his retirement.

MINUTES NO. 93

Southwest Power Pool
BOARD OF DIRECTORS MEETING
Westin Oklahoma City
April 27, 2004

Agenda Item 1 - Administrative Items
SPP Chair Mr. Al Strecker called the meeting to order at 9:01 a.m. and thanked everyone present and participating by phone for attending. Mr. Strecker then called for a round of introductions and referred to the agenda (Agenda – Attachment 1). The following Board members were in attendance or represented by proxy:

Ms. Phyllis Bernard, independent director
Mr. Nick Brown, Southwest Power Pool
Mr. David Christiano, City Utilities of Springfield, MO
Mr. Harry Dawson, Oklahoma Municipal Power Authority
Mr. Michael Deihl, Southwestern Power Administration
Mr. Jim Eckelberger, independent director
Ms. Trudy Harper, Tenaska Power Services Company
Mr. Doug Henry, Westar
Mr. Quentin Jackson, independent director
Mr. Joshua Martin, independent director
Mr. Mike Palmer, Empire District Electric Company
Mr. Stephen Parr, Kansas Electric Power Cooperative
Mr. Gary Roulet, Western Farmers Electric Cooperative
Mr. Robert Schoenberger, independent director
Mr. Harry Skilton, independent director
Mr. Richard Spring, Kansas City Power & Light
Mr. Jim Stanton, Calpine
Mr. Al Strecker, OG+E
Mr. Richard Verret, American Electric Power
Mr. Gary Voigt, Arkansas Electric Cooperative Corporation
Mr. Walt Yeager, Cinergy Services

There were 58 persons in attendance representing 27 members and 9 regulators (Attendance List - Attachment 2). Mr. Brown reported no proxies and a quorum was declared.

Mr. Strecker referred to draft minutes of the March 16 meeting (3/16/04 Meeting Minutes - Attachment 3) and asked for corrections or a motion for approval. Mr. Dawson moved that the minutes be approved as presented. Mr. Martin seconded the motion, which passed unopposed.

Agenda Item 2 – President's Report
Mr. Nick Brown presented the President's Report (Executive Quarterly Report – Attachment 4). He stated that Southwest Power Pool plans to make a compliance filing the first week in May to meet the conditions in the Federal Energy Regulatory Commission (FERC) order in the SPP RTO filing docket RT04-1 issued on February 10, 2004. With actions taken at the March Board meeting and actions expected in today's meeting, Southwest Power Pool is prepared to meet the six conditions in the FERC order. Mr. Brown stated that the Board released funding for the Imbalance Market last month and training is beginning on May 18 with Market 101 in Kansas City. Mr. Brown stated that he and Mr. Tom Dunn (SPP) had met with Standard & Poor's on April 20 to update SPP's investment rating. Mr. Brown said that letters had gone out to members to rescind withdrawal letters to better qualify but no one had rescinded their withdrawal.

Mr. Brown addressed the NERC initiatives stating that since the August 14 Blackout there had been an accelerated transition to Version 0 of the Reliability Standards. Regional managers received a letter from FERC Commissioner Pat Wood encouraging awareness and actions to address 14 Blackout recommendations from the NERC. This has raised the bar for SPP and caused recognition of weaknesses that are being addressed.

Agenda Item 3 – Regional State Committee Report

Oklahoma State Commission Chairman, Denise Bode was asked to give the Regional State Committee (RSC) Report. Chairman Bode stated that this was an historic occasion with the formation of the SPP RSC, which would act as a bridge between state and federal regulators. In their first meeting (April 26), the RSC adopted bylaws and elected the following officers: President, Denise Bode (OCC); Vice President, Sandra Hochstetter (APSC); Secretary, Julie Parsley (PUCT); and Treasurer, David King (NMPRC). Chairman Bode said that the next step would be development of a budget. Initiatives of the RSC are to become a contracting party for the cost-benefit study and to provide leadership in the upgrading and expansion of transmission facilities. A document has been drafted which outlines direction for the group and will be discussed at a May 5 RSC meeting. In the future it is planned to hold regular meetings the day prior to the SPP Board of Directors meetings and to work with the SPP Staff, their next meeting being July 26 in Kansas City.

Agenda Item 4 – Strategic Planning Committee Report

Mr. Richard Spring presented the Strategic Planning Committee Report (SPC Report – Attachment 5). Mr. Spring stated that the SPC formed a Cost-Benefit Task Force (CBTF) comprised of the following:

- SPC Members: Richard Spring, Michael Desselle, Ricky Bittle, Mel Perkins
- Other Members and/or Member technical experts: Robin Kittel, Shah Hossain
- RSC Representatives: Sam Loudenslager, John Cita, Kelli Leaf, Ken Zimmerman
- SPP Staff: Jeff Price

The CBTF developed a scope of the project for the independent consultant(s) to oversee the study, general contract terms for those services (CBTF Scope – Attachment 6). It was concluded that a coordinated study was preferred over independent studies and that all SPP Members share the costs. A Request for Proposal (RFP) has been developed to distribute to 8 potential vendors (RFP – Attachment 7). Mr. Spring moved that the Board approve the following recommendation:

> The SPC recommends that the approach described be approved for pursuit of a cost-benefit study, including authorization for this project as an unbudgeted item for FY2004. The SPC will present an exact expenditure request and a methodology for inclusion of the RSC for approval following receipt of proposals and selection of a vendor.

Mr. Schoenberger seconded the motion, which passed unanimously. Further discussion clarified that the RFP is in draft, and the final RFP would be changed to require a study that is not limited to “vertically integrated State jurisdictional utilities” (IOU’s) but would be “broad based” including a cost/benefit study for entities like SWPA.

Agenda Item 5 – Independent Market Monitor Selection Task Force Report

Mr. Jim Stanton presented the Independent Market Monitor Selection Task Force Report (IMMSTF Report – Attachment 8). Mr. Stanton recognized members of the IMMSTF as: Jim Stanton (Calpine), Chair, Seth Brown (ETEC), Joshua Martin (independent Director), Mel Perkins (OG&E), Richard Ross (AEP), Bob Schoenberger (independent Director); Carl Monroe is the SPP staff member with assistance from Richard Dillon. Four vendors submitted bids to SPP in response to the RFP. After reviewing the bid documents, the IMMSTF met with three vendors for oral presentations on April 13. Following the oral presentations, the IMMSTF evaluated each vendor. An evaluation matrix was developed to aid in the process. The vendor chosen was Boston Pacific out of Washington D.C. The Board took note of concerns expressed about the potential for inequities and disproportionalities in the allocation of costs, and instructed the OPC and, later the IMM, to closely monitor these issues. Mr. Stanton moved that the following recommendation be approved:

> Based on review of the proposals and evaluation of the vendors, the IMMSTF recommends that the Board of Directors ratify the selection of Boston Pacific and direct the SPP staff to develop and execute a contract under the SPP contract approval guidelines for the engagement of the Independent Market Monitor, absent any material deviation from the proposal.

Mr. Josh Martin seconded the motion, which passed unanimously.

Agenda Item 6 – Operations Policy Committee

Mr. Mel Perkins presented the Operations Policy Committee Report (OPC Report – Attachment 9). Mr. Perkins stated that the OPC had the following recommendations to present to the Board for approval:

- SPP Criteria 2 (Attachment 10): These changes are to clarify criteria concerning adequate capacity. Mr. Brown moved to approve changes to Criteria 2. Mr. Henry seconded the motion, which passed unanimously.
- Modification to Tariff Part IV including addition of Section 39 (Attachment 11): Language was proposed by Mike Small to clarify that SPP is the sole transmission provider meeting conditions of the February 10 Order granting SPP RTO Status. Mr. Palmer moved to approve this recommendation. Mr. Yeager seconded the motion, which passed unanimously.
- Modifications to Tariff Attachment O (Attachment 12): The proposed changes are to provide SPP with the authority to independently oversee the regional transmission plan and solely determine the priority of transmission planning projects that address reliability and economic needs. Mr. Stanton moved to approve Attachment O modifications. Mr. Roulet seconded the motion, which passed with Mr. Dawson abstaining.
- Modifications to Attachment P (Attachment 13): This is to change the Non-Firm hourly "No Later Than" Energy Scheduling deadline from 1500 day prior to 20 minutes prior to the hour. The change facilitates conduct of the Non-Firm hourly market. Ms. Harper moved to approve modifications to Attachment P. Mr. Yeager seconded the motion, which passed unanimously.
- Addition of new Tariff Attachment Z (Attachment 14): SPP proposes to implement a process that allows aggregation of multiple requests received during a specified time frame into a single study. This will allow SPP to process multiple requests together improving the response time for long-term requests. Additionally, cost sharing of upgrades will be implemented to distribute the costs of upgrades that provide benefit to multiple requests. There were concerns about the cost-sharing problem but felt these concerns would be addressed in the participant funding process. Mr. David Brian presented a memo (Memo – Attachment 15) stating concerns with Tariff Attachment Z and Attachment AA. Following much discussion, Mr. Stanton moved to approve the recommendation for the addition of Attachment Z. Mr. Skilton seconded the motion, which passed with Ms. Harper in abstention and Mr. Eckelberger, Mr. Christiano and Mr. Dawson in opposition.
- New Tariff Attachment AA (Attachment 16): Under this proposal transmission customers have the optional ability to prepay for transmission service. This prepayment shall be provided back to the customer as a credit. The prepayment will be placed in an interest bearing account with the interest added to the credited amount. The credits will be applied to the customer's monthly invoice at the time the transmission owner expenditures occur. This shall continue until the customer has been fully reimbursed for the prepayment. This attachment is to be a one-year experiment. Mr. Stanton moved to approve Attachment AA. Mr. Roulet seconded the motion, which passed unanimously.
- Modifications to Service Schedule 4-A (Attachment 17): These modifications are to:
  1. Clarify that Schedule 4-A would only apply to transactions across Control Area boundaries;
  2. Provide a default basis for allocation of generation output among multiple schedules from a single generator where the generation operator fails to provide a timely basis for settlement;
  3. Set a reasonableness standard for acceptance of other arrangements as alternatives to Schedule 4-A; and

4. Establish a new pricing basis for the charges under Schedule 4-A, replacing the use of the individual Transmission Owner's FERC approved Schedule 4 rates.

Mr. Voigt moved to approve Attachment 4-A. Mr. Henry seconded the motion, which passed with Mr. Dawson in abstention.

Mr. Perkins then gave a brief overview of current activities of the 14 working groups reporting to the OPC, including updates on Market implementation, transmission planning, actions on Blackout recommendations, seams efforts and the compliance program.

Agenda Item 7 – Corporate Governance Committee Report

Mr. Brown presented the Corporate Governance Committee Report (CGC Report – Attachment 18). He stated that this committee, formerly the Nominating Task Force, consists of the following members representing each sector: David Christiano (municipals), Steve Parr (cooperatives), Mike Deihl (federal agencies), Nick Brown, Al Strecker (investor owned utilities), and Jim Stanton (IPP market). In the FERC Order conditionally granting SPP RTO status, it was clearly required to transition to a non-stakeholder Board of Directors. This transition also included a new committee structure for the *Committees Reporting to the Board of Directors*, per Section 6.0 of the Bylaws effective May 1, 2004. Mr. Brown moved to approve the following recommendation:

> The Corporate Governance Committee recommends that the Board of Directors approve the slate of nominees presented for the Committees Reporting to the Board of Directors to become effective May 1, 2004.

Mr. Yeager seconded the motion, which passed unanimously.

Agenda Item 8 – Finance Working Group Report

Mr. Harry Skilton gave the Finance Working Group report (FWG Report – Attachment 19). The Board of Directors established a Finance Committee in its draft bylaws submitted with SPP's RTO application to the FERC. Mr. Skilton stated that a scope document has been developed as a charter to support the existence of the Finance Committee. Mr. Skilton moved to approve the following recommendation:

> The Finance Working Group recommends the SPP Board of Directors accept the Finance Committee Scope Statement as the charter of the Finance Committee, and approve the detailed responsibilities and authorities of the Finance Committee.

Mr. Eckelberger seconded the motion, which passed unanimously.

Other Business

Mr. Eckelberger reported that the Employee Benefit Working Group (EBWG) had picked the best of 3 contractors to do an employee survey as authorized by Mr. Tom Dunn. The results should be available in two to three months and will be reported to the Board of Directors.

The next Board of Directors Meeting will be a special teleconference meeting held sometime in late May. Possible issues to be addressed are: Criteria 4, Funding for the Cost-Benefit Study, filings in Arkansas and Kansas and possible others, and final approval of financing. The next regular Board meeting will be July 27 in Kansas City.

Mr. Brown announced that there was a scheduled press conference following the Board meeting at 12:00 p.m. All were invited to attend. The Special Meeting of Members is to begin at 1:00 p.m. Mr. Brown then made a presentation to Mr. Strecker in honor of his retirement on June 1. Mr. Strecker was presented with a clock for his future office and a resolution for his exemplary service to SPP (Strecker Resolution – Attachment 20). Mr. Brown moved that this resolution be accepted. Mr. Palmer seconded the motion, which passed unanimously. Mr. Christiano acknowledged that Marvin Caraway (City of Clarksdale, Mississippi) was also retiring and had served many years in this business.

Adjournment
With no further business, Mr. Strecker thanked everyone for participating and adjourned the meeting at 11:32 p.m.

Stacy Duckett, Corporate Secretary

MINUTES NO. 94

Southwest Power Pool
BOARD OF DIRECTORS/MEMBERS COMMITTEE
Teleconference Minutes
June 2, 2004

Agenda Item 1 – Governance Issues
Mr. Nick Brown called the meeting to order at 1:05 p.m. in the absence of an SPP Board chairman and thanked everyone present for attending. The following Board/Members Committee members were in attendance or represented by proxy:

- Ms. Phyllis Bernard, director,
- Mr. Nick Brown, director,
- Mr. Jim Eckelberger, director,
- Mr. Quentin Jackson, director,
- Mr. Joshua Martin, director,
- Mr. Robert Schoenberger, director,
- Mr. Harry Skilton, director,
- Mr. David Christiano, City Utilities of Springfield, MO,
- Mr. Harry Dawson, Oklahoma Municipal Power Authority,
- Mr. Michael Deihl, Southwestern Power Administration,
- Mr. Michael Desselle, American Electric Power,
- Ms. Trudy Harper, Tenaska Power Services Company,
- Mr. Bary Warren for Mike Palmer, Empire District Electric Co.,
- Mr. Steve Parr, Kansas Electric Power Cooperative,
- Mr. Gary Roulet, Western Farmers Electric Cooperative,
- Mr. Richard Spring, Kansas City Power & Light,
- Mr. Jim Stanton, Calpine Energy Services,
- Mr. Rick Tyler, Northeast Texas Electric Cooperative,
- Mr. Ricky Bittle, for Mr. Gary Voigt, Arkansas Electric Cooperative Corp.,
- Mr. Walt Yeager, Cinergy Services

SPP Staff included Carl Monroe, Tom Dunn, Les Dillahunty and Stacy Duckett. Guests participating included Tom DeBaun (KCC), David King (New Mexico PUC), Shah Hossain and Burton Crawford (Westar), Paul Mahlberg (City of Independence), Robin Kittel (Xcel), Mel Perkins (OG+E), and Mike Proctor (MoPSC). The teleconference continued with a full agenda (Agenda – Attachment 1).

Ms. Stacy Duckett reviewed the staff recommendation related to terms for SPP's new governance structure, consisting of a seven-member Board of Directors and a 16-member Members Committee, which became effective May 1. Representatives of both groups are to serve staggered 3-year terms. Representatives were assigned classes using a random system (SPP Board/Members Committee Terms – Attachment 2). SPP Officers recommend that the Board of Directors confirm the terms as presented, with the current terms expiring 2005, 2006, and 2007 so as to avoid half-year terms ending at the end of 2004, and also to retain the change in terms with the fiscal year. Mr. Jackson moved to approve this recommendation. Mr. Martin seconded this motion, which passed. Following this action, the Board of Directors elected its Chair and Vice Chair. Mr. Joshua Martin moved that Mr. Jim Eckelberger be elected Chair and Mr. Harry Skilton be elected Vice Chair. The motion passed.

Agenda Item 2 – Administrative Items

Mr. Eckelberger assumed responsibilities as Chair of the Board. Approval of minutes from the April 27, 2004, Board of Directors meeting was postponed until the July 27 meeting pending some proposed changes/clarifications.

Agenda Item 3 – Market and Operations Policy Committee Report – Criteria 4

Mr. Mel Perkins presented Criteria 4 and Appendix 9 changes and the purpose of these changes (MOPC Report & Recommendation – Attachment 3). Revising Criteria 4 is important because several service requests for this summer are pending the outcome. Ms. Robin Kittel provided additional information as vice-chair of the MOPC. Following discussion, Mr. Skilton requested input regarding dissenting votes at the MOPC meeting, which information was provided. Mr. Skilton moved to approve the recommended changes to Criteria 4, including Appendix 9 with revisions removing the review and approval by TWG and ORWG, which revision retains Board authority over future changes (Revised Criteria 4 – Attachment 4). Mr. Schoenberger seconded this motion, which passed. A Members Committee straw vote was taken resulting in unanimous support.

Agenda Item 4 – Finance Committee Report

Mr. Skilton introduced the Regional State Committee (RSC) budget. The Finance Committee approved the estimated budget included in the report (Finance Committee Report – Attachment 5). The RSC revised this budget at their meeting earlier today, which was distributed prior to the Board teleconference (RSC Revised Budget – Attachment 6). The RSC requests approval of the revised budget for a 2-year period, July 2004 through July 2006. Mr. Skilton moved to approve the RSC budget as revised. Ms. Bernard seconded the motion. In discussion, it was pointed out that the budget does not include funding for the Cost-Benefit Study since details are still pending. David King stated that the budget presented is an absolute cap on spending from the RSC. The motion passed. The Members were supportive with one abstention.

Mr. Skilton reviewed the SPP Audit and process of review with the auditors (SPP Audit – Attachment 7). Mr. Skilton moved to approve the audit as presented. Mr. Martin seconded the motion, which was approved. The Members had no comment.

Mr. Skilton presented the term sheet and reviewed key details of the terms for the long-term financing (Terms Agreement – Attachment 8). Mr. Tom Dunn updated all on the SPP credit rating. He stated that SPP is reviewing the current note agreement and asking the lender to make revisions so that the existing and new terms will mirror each other in material aspects. In addition, staff was directed to pursue an amendment to the membership withdrawal provisions of the agreements to clarify that a member disavowal of its obligation must be court sanctioned in order to be valid and thus a potential default. Mr. Skilton moved to approve the SPP Board of Directors resolution to borrow $25,000,000 per the terms outlined in the recommendation and in the Note Purchase Agreement. Mr. Jackson seconded the motion, which passed. The Members agreed with one abstention.

Mr. Skilton introduced the Sarbanes Oxley (SOA) 404 certification requirements (SOA Recommendation – Attachment 9). Although SPP is not subject to the Act, many of its members are. Mr. Skilton moved to approve and Mr. Schoenberger seconded the following recommendation:

> SPP staff recommend the company move forward with engaging an independent firm or an internal audit team staffed from member firms to conduct a Billing and Settlements Audit to assist our SEC registered members in satisfying their SOA 404 certifications requirements. The costs associated with the Billing and Settlements Audit will be shared by those members utilizing the audit. Additionally, staff recommends development of a longer-term plan to include SAS70 preparation work during 2004. Finally, a SAS70 level II Audit will be planned for 2005 assuming consensus of SPP/s SEC registered members that this audit is required. The costs associated with this audit will be shared by those members utilizing the audit report. SPP staff is currently investigating the costs to implement this recommendation.

Mr. Dunn explained members' needs in regards to the SOA 404 requirements and documentation of controls. No monies are budgeted in 2004 and SPP cannot realistically accomplish SAS70 level II audit in 2004. He suggested Members that have an obligation should be asked to provide feedback as to what is necessary now and SPP should prepare for a SAS70 level II audit in 2005. The motion passed as presented. Additional discussion is to be had at the July Board of Directors meeting. It was decided that Mr. Spring would organize a call among auditors from the members affected to further discuss and define needs. Mr. Brown and Mr. Dunn will assist.

Agenda Item 5 – State Filing Authorization

Mr. Brown presented a recommendation regarding state filings and their necessity (State Regulatory Filings – Attachment 10). SPP Bylaws require the Board of Directors' approval to make regulatory filings. Mr. Brown moved to approve the following recommendation:

> Pursuant to Section 4.1.n of SPP's Bylaws, Staff recommends that the Board of Directors authorize the filing of applications for limited Certificates of Public Convenience and Necessity in the states of Arkansas and Kansas.

Mr. Martin seconded the motion, which passed. The Members were in agreement.

Other Business

Mr. Eckelberger asked Ms. Duckett to review the Bylaws and consider other/additional options to the secret ballot voting currently required.

Future Meetings

The next Board of Directors meeting is Tuesday, July 27, 2004 in Kansas City, Missouri, at the Embassy Suites KCI from 10:00 a.m. to 3:00 p.m.

Adjournment

With no further business, Mr. Eckelberger thanked everyone for participating and adjourned the teleconference at 3:05 p.m.

Stacy Duckett, Corporate Secretary

Southwest Power Pool
Regional State Committee and Board of Directors/Members Committee
Future Meeting Locations

2005

January 24-25, 2005	Shreveport, LA
April 25-26, 2005	Austin, TX
July 25-26, 2005	Tulsa, OK
October 24-25, 2005 (Annual Meeting of Members)	Santa Fe, NM

2006

January 30-31, 2006	New Orleans, LA
April 24-25, 2006	Oklahoma City, OK
July 24-25, 2006	Kansas City, KS
October 23-24, 2006 (Annual Meeting of Members)	Little Rock, AR

All proposed dates are the last Monday and Tuesday of the month except for October 2006, which is the next to the last.

The RSC meeting will be held on Monday afternoon and the BOD/Members Committee meeting on Tuesday of each of the proposed dates. The exception is the Tuesday of the October dates during which the BOD/Members Committee will meet in the morning, followed by the Annual Meeting of Members in the afternoon.

SUMMARY

	2Q 2004	1Q 2004
Assessments/Tariff Fees	$20.8M (YTD)	$9.8M
Cash	$41.2M (YTD)	$12.0M
Operating Cash Flow	$8.4M (YTD)	$2.6M
Operating Expenses	$14.1M (YTD)	$7.4M
TLR Events	55	23
Tags (daily average)	520	489
Transmission Service Requests	32,901	27,844
Transmission Service Study Queue	132 requests/ 61 studies	122 requests/ 53 studies
Generation Interconnection Queue	40 requests	50 requests
Stakeholder Meetings	40	42
FERC Dockets Pending	7	7
Lawsuits Pending	0	1
Officer Speaking Engagements	17	5
Number of Members	48	48
Withdrawal Notices	16	12
Staff	128	119

NOTES TO FINANCIAL STATEMENTS

Balance Sheet

- SPP closed and funded $25 million in 4.78% senior notes on June 25.
- Established "capital funding account" with proceeds from $25 million debt issue and the $3.3 million in excess collections received in 2003. Funds from this account will only be utilized to pay for capital expenditures.
- Member's Equity account is increasing due to excess of revenues over expenses during the 2004 fiscal year.

Income Statement

- Revenues are 5% ahead of budget, primarily due to higher than estimated billing determinants.
- Operating expenses are below budget as a result of:
    - Staffing levels remain below budget (currently 12 open positions);
    - SPP has not implemented enhanced maintenance agreements on its systems originally expected in the 1Q'04;
    - Delay in implementation of imbalance market has deferred anticipated consulting costs.
    - Staff able to manage overhead expenses to less than budgeted levels.
- Anticipate “catch-up” several areas during the remainder of the year.

Cash Flow

- Cash position increased by $26 million from FYE’03, primarily the result of receipt of proceeds from debt issuance.
- Operations generated a positive cash flow of $8.4MM; 2004 forecast indicated a net cash shortfall during 1Q.
- Positive cash from operations used to fund $5 million principal payment on 7.5% senior notes and $2.1 million in capital expenditures.

Capital Expenditure Summary

- The capital expenditures summary reflects the delay in the implementation of the energy imbalance and market monitoring projects. Anticipate “catch-up” during the remainder of the year.

Southwest Power Pool
Budget Performance
June 2004

	Jan - Jun 04	YTD Budget	$ Over Budget
Ordinary Income/Expense			
Income			
Miscellaneous Income	1,322,784	1,072,000	250,784
Tariff/Assessment	19,831,543	18,624,859	1,206,684
Member Fees	1,078,185	1,144,951	-66,766
Total Income	22,232,512	20,841,810	1,390,702
Expense			
Salary & Benefits	7,113,340	8,392,905	-1,279,565
Employee Travel	250,263	435,561	-185,298
Administrative	534,977	770,475	-235,498
NERC Assessment	502,648	400,000	102,648
SPP/NERC Meetings	130,078	266,210	-136,132
Communications	592,690	815,886	-223,196
Leases & Maintenance	1,619,596	2,440,066	-820,470
Services	3,351,511	4,179,290	-827,779
Total Expense	14,095,103	17,700,393	-3,605,290
Net Ordinary Income	8,137,409	3,141,417	4,995,992
Other Income/Expense			
Other Income			
Gain/Loss on Sale Fixed Asset	2,000	0	2,000
Total Other Income	2,000	0	2,000
Other Expense			
Amortization	20,194	0	20,194
Bad Debt Expense	48,862	0	48,862
Depreciation	2,218,123	2,340,000	-121,877
Interest Expense	929,846	843,750	86,096
Total Other Expense	3,217,024	3,183,750	33,274
Net Other Income	-3,215,024	-3,183,750	-31,274
Net Income	**4,922,385**	**-42,333**	**4,964,718**

Southwest Power Pool
Balance Sheet
As of June 30, 2004

		Jun 30, 04	
ASSETS			
Current Assets			
Checking/Savings		41,151,614	
Accounts Receivable		22,318,484	
Other Current Assets		528,520	
Total Current Assets			63,998,619
Fixed Assets			
Equipment and machinery			
***Equipment and machinery - cost**	5,109,940		
Accumulated Depreciation - E&M	(3,652,699)		
Total Equipment and machinery		1,457,241	
Furniture and fixtures			
***Furniture and fixtures - cost**	2,237,125		
Accumulated Depreciation - F&F	(1,415,344)		
Total Furniture and fixtures		821,781	
Software			
***Software - cost**	14,014,722		
Accumulated Depreciation - SW	(11,368,396)		
Total Software		2,646,326	
Software Under Development		14,842,079	
Total Fixed Assets			19,767,426
Other Assets			263,412
TOTAL ASSETS			**84,029,457**
LIABILITIES & EQUITY			
Liabilities			
Current Liabilities			
Total Accounts Payable	18,892,230		
Total Other Current Liabilities	18,808,906		
Total Current Liabilities		37,701,136	
Long Term Liabilities			
4.78% Senior Notes - 2011	25,000,000		
7.5% Senior Notes - 2008	15,000,000		
Total Long Term Liabilities		40,000,000	
Total Liabilities			77,701,136
Equity			
Retained Earnings		1,405,936	
Net Income		4,922,385	
Total Equity			6,328,321
TOTAL LIABILITIES & EQUITY			**84,029,457**

Southwest Power Pool
Statement of Cash Flows
January through June 2004

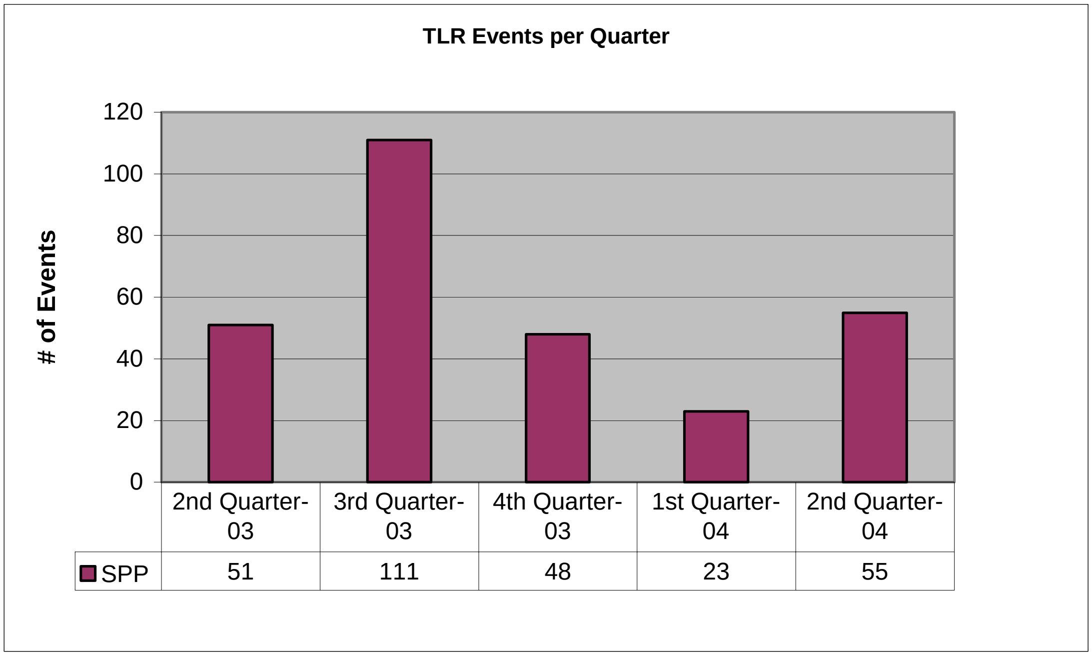
	Jan - Jun 04
OPERATING ACTIVITIES	
Net income (loss)	4,922,385
Adjustments to reconcile net income (loss) to net cash provided by operations:	
Depreciation	2,218,123
Amortization	20,194
Changes in assets and liabilities:	
Accounts receivable	(1,116,006)
Prepaid expenses	(213,307)
Accounts payable	1,119,960
Other current liabilities	(196,613)
Customer deposits	1,633,217
Net cash provided (used) by operating activities	8,387,953
INVESTING ACTIVITIES	
Purchase of property and equipment	(2,144,593)
Net cash provided (used) by investing activities	(2,144,593)
FINANCING ACTIVITIES	
Issue of 4.78% Senior Notes - 2011	25,000,000
Repayment on 7.5% Senior Notes - 2008	(5,000,000)
Loan acquisition costs	(202,833)
Net cash provided (used) by financing activities	19,797,167
Net cash increase (decrease) for period	26,040,528
Cash at beginning of period	15,111,086
Cash at end of period	**41,151,614**

Southwest Power Pool
Capital Expenditures

Southwest Power Pool
Capital Expenditures by Project (Summary)

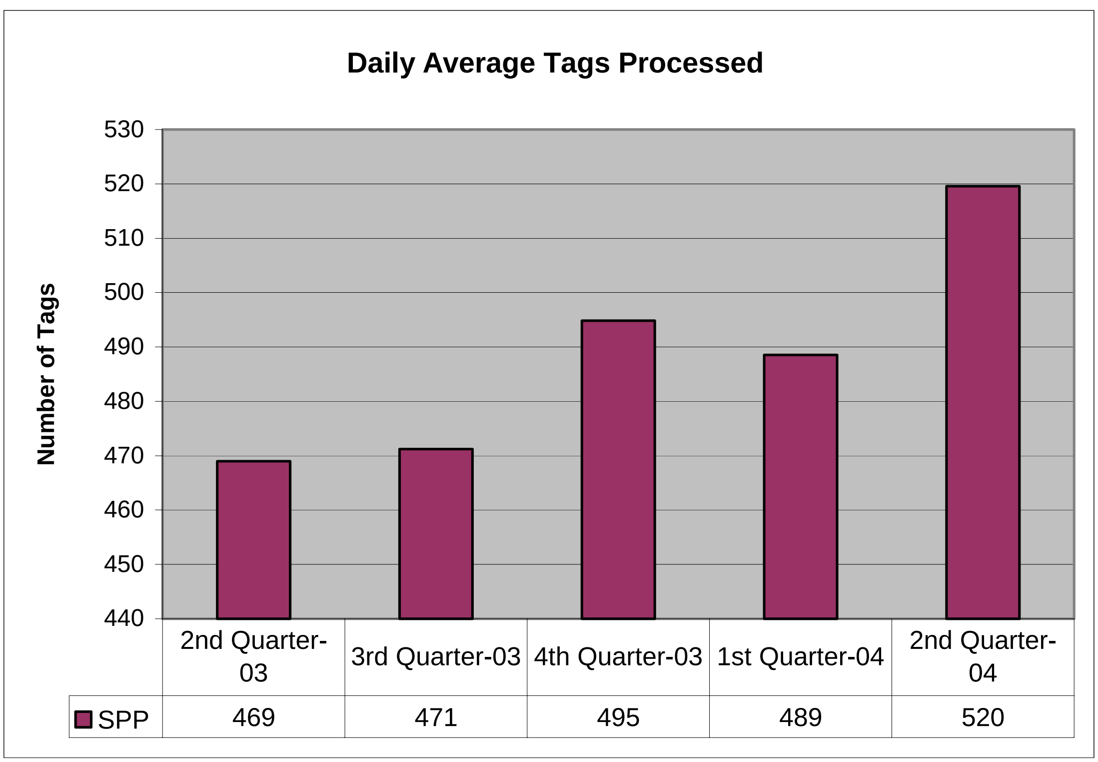
	Jan-Jun 04	Budget	$ Over Budget
Disaster Recovery Site	57,953	1,069,125	-1,011,172
Maintenance - Hardware	111,930	804,890	-692,960
Maintenance - Servers	63,377	157,940	-94,563
Maintenance - Software	277,574	716,965	-439,391
Maintenance - Routers and Switches	187,132	213,600	-26,468
Market Project	1,374,684	4,509,455	-3,134,771
OASIS AFC Granualarity Project	71,944	140,000	-68,056
Total Capital Expenditures	**2,144,593**	**7,611,975**	**-5,467,382**

RELIABILITY COORDINATION



2Q04 v. 2Q03 shows slight increase in number of events.

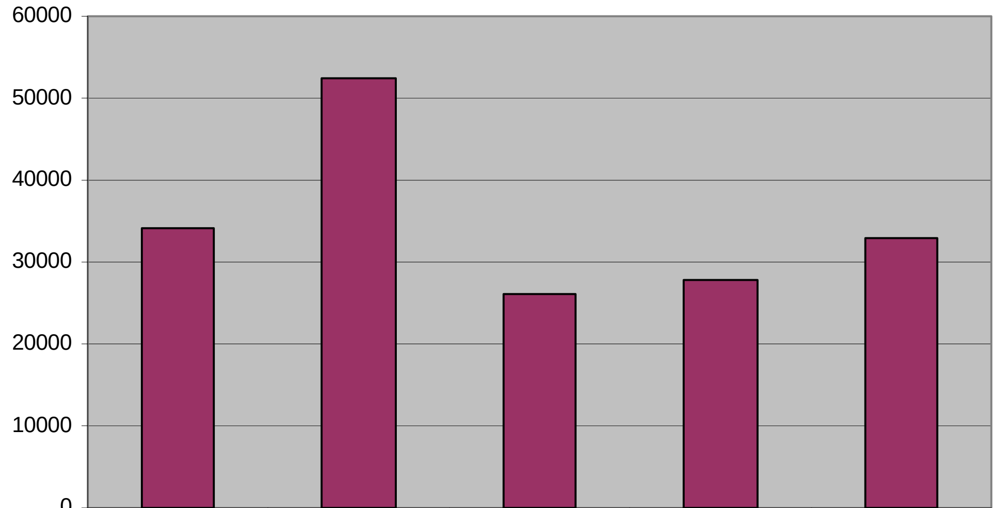
SCHEDULING



2Q04 v. 2Q03 shows increase in the number of tags processed.

TARIFF ADMINISTRATION

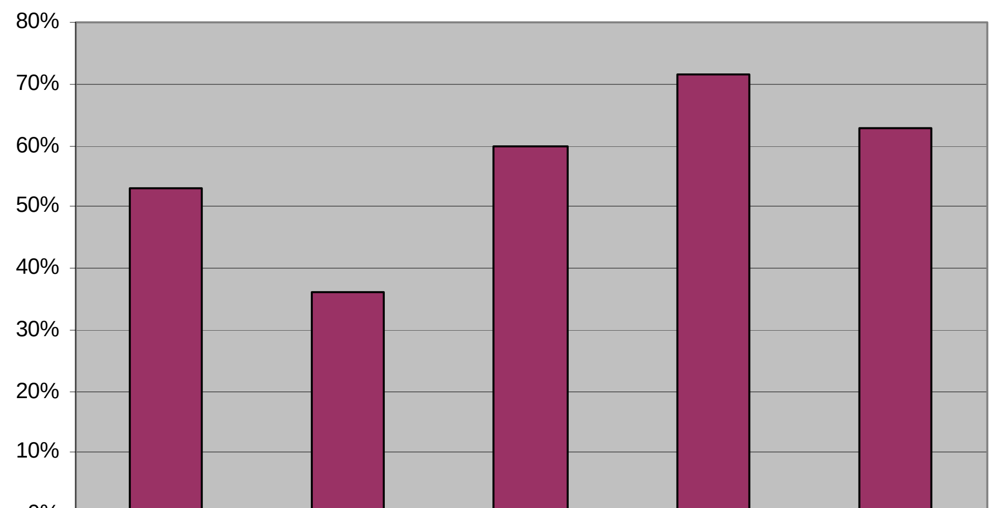
Total Requests Submitted



	2nd Quarter 03	3rd Quarter 03	4th Quarter 03	1st Quarter 04	2nd Quarter 04
SPP	34197	52389	26101	27844	32901

2Q04 v. 2Q03 shows slight decrease in total transmission service requests.

% of Total Requests that are Confirmed



	2nd Quarter 03	3rd Quarter 03	4th Quarter 03	1st Quarter 04	2nd Quarter 04
SPP	53%	36%	60%	71%	63%

2Q04 v. 2Q03 shows increase in percentage of transmission service requests granted.

QUEUE STATUS REPORT

Transmission Service Request Queue

Number of requests/studies = 132 / 61, representing 10,143 MW

Average processing time for a non-DC tie request System Impact Study is 160 days.

There are 50 requests/17 studies for DC Tie requests representing 2229 MW that cannot be processed due to impending DC Tie competition.

During the same period last year, there were 170 requests/105 studies in process, representing 12260 MW. There were 130 requests/ 77 studies for DC Tie requests representing 10001 MW that could not be processed due to impending DC Tie competition. Average processing time for a non-DC Tie request System Impact Study was 200 days.

Generation Interconnection Queue

Number of requests = 40, representing 9946 MW

- Number of wind requests = 29, representing 5087 MW
- Number of fossil fuel requests = 11, representing 4859 MW

Number of requests with Interconnection Agreement pending = 11

During the same period last year, there are 35 requests in process (26 wind; 9 fossil fuel) representing 7,130 MW (3,576 MW wind; 3,554 MW fossil fuel). There were 16 Interconnection Agreements pending.

SPP DOCKETS AT FERC

DOCKET NUMBER	CASE NAME	DESCRIPTION	CURRENT STATUS
ER99-4392	**East Texas Electric Cooperatives, Inc. v. FERC**	SPP filed revisions to its tariff in order to implement network integration transmission service. ETEC filed for rehearing and was denied by FERC. ETEC appealed to the Court of Appeals. The case was dismissed in part and remanded in part to decide whether ETEC facilities within the SPP region are integrated with the SPP transmission system.	This docket was remanded back to FERC by Court of Appeals. SPP is awaiting FERC action
ER03-765	**Calpine Oneta Power, L.P**	Calpine Oneta filed a rate schedule intended to allow it to provide Reactive Power Service to SPP and charge SPP based on an annual revenue requirement of $2.7M. SPP intervened asserting that Calpine Oneta had not made an adequate showing that it is entitled to compensation, and that SPP only acts as a conduit to collect Reactive Power Service charges and pass the revenues through to the provider of the service.	On January 29, Calpine Oneta submitted a motion to suspend the procedural schedule to allow the parties to try to resolve the issues through the SPP stakeholder process. That motion was granted by order issued February 5, 2004.
EC03-131	**Oklahoma Gas & Electric Company and NRG McLain**	OG&E and NRG filed an application for OG&E to acquire NRG's ownership interest in the McLain generating facility. FERC stated that the proposed transaction could have an adverse effect on competition, and set established hearing procedures. One of the issues set for hearing is whether a third-party should perform the disputed tariff functions until SPP is determined to be a fully independent ISO or RTO.	In July 2 Order, FERC approved settlement proposal set forth by OG&E. The issue of whether SPP should provide tariff functions before it is a functioning RTO was resolved by OG&E's proposal to provide an independent market monitor to oversee the ATC and TTC calculations.

DOCKET NUMBER	CASE NAME	DESCRIPTION	CURRENT STATUS
RT04-01 and ER04-48	**Southwest Power Pool, Inc.**	SPP filed a proposal for recognition as an RTO. By order issued February 10, the Commission accepted SPP's proposal for recognition as an RTO subject to conditions and compliance filing requirements. On July 2, 2004, FERC issued an order on SPP's RTO Compliance Filing (RTO4-1-002) outlining the remaining conditions.	SPP is currently making the necessary changes to its governance, organic documents, and tariff in order to comply with the recent order.
ER04-434	**Southwest Power Pool, Inc.**	SPP filed revisions to its Tariff in compliance with FERC Order No. 2003, as well as other related revisions to its Tariff. It specifically addressed the LGIA and LGIP. On April 19, 2004, SPP made a ministerial filing adopting the Order 2003 pro forma LGIA and LGIP in compliance with FERC's March 19 Order. One June 21, 2004, FERC accepted SPP's April 19, 2004 filing adopting the Order 2003 pro forma LGIA and LGIP.	SPP made its compliance filing of a modification to its pro forma agreement allocating responsibilities between SPP and the transmission owners with regard to generation interconnections.
ER04-658	**Southwest Power Pool, Inc.**	SPP filed miscellaneous revisions to its Tariff	In a letter order dated May 26, 2004, FERC accepted the proposed tariff revisions.
ER04-853	**Southwest Power Pool, Inc.**	SPP filed Attachment AA to add an experimental customer pre-payment option to support construction of transmission facilities to facilitate incremental transmission service, especially short-term service. On July 7, 2004, FERC issued a letter order regarding the filing of Attachment AA requiring additional information.	SPP is preparing the additional information for submittal to FERC.

EXECUTIVE SPEAKING ENGAGEMENTS

Speaker	Event
Nick Brown	New Mexico Public Service Commission
	Kansas Corporation Commission
	Louisiana Public Service Commission
	SPP Participant Funding Symposium II
	Kansas Society of Professional Engineers Annual Conference
	Mid America Regulatory Commissioners Conference
	West Little Rock Rotary Club
	Kansas Corporation Commission
	East Texas Electric Cooperatives Members Meeting
Les Dillahunty	SPP Mini-Participant Funding Symposium
	SPP Participant Funding Symposium II
	Mid America Regulatory Commissioners Conference
Carl Monroe	SPP Market Synopsis 101 [3 sessions]
	SPP Regional Planning Summit II
	SPP Participant Funding Symposium II

WITHDRAWAL LETTERS

MEMBERS	EFFECTIVE DATES
American Electric Power	10/31/04
Cleco Corporation	10/31/04
Dynegy Marketing and Trade	10/31/04
East Texas Electic Cooperative	10/31/04
El Paso Merchant Energy, L.P.	10/31/04
The Empire District Electric Company	10/31/04
Grand River Dam Authority	10/31/04
Kansas City Power & Light Company	10/31/04
Louisiana Energy & Power Authority	10/31/04
City of Lafayette Utilities System	10/31/04
Northeast Texas Electic Company	10/31/04
Oklahoma Municipal Power	10/31/04
Southwestern Power Administration	10/31/04
Tex-La Cooperative of Texas	10/31/04
Westar Energy	10/31/04
Southwestern Public Service (Xcel Energy)	10/31/04

STAFFING REPORT

SPP Employee count as of January 1, 2004:	116
1Q New hires:	6
2Q New hires:	11
YTD Terminations:	5
1 – Retiree	
3 – Voluntary terminations	
1 – Involuntary termination	
SPP Employee count as of June 30, 2004:	128
SPP Employee count as of June 30, 2003:	105

There are 142 full time employees in the 2004 budget.

Southwest Power Pool

Southwest Power Pool, Inc.

STRATEGIC PLANNING COMMITTEE

Report to the Board of Directors

July 27, 2004

Background

On July 2, 2004, the Federal Energy Regulatory Commission (the "Commission") issued an order in response to the compliance filing in the SPP RTO docket accepting in part, but requiring more work/information in some areas. The Commission requires another compliance filing by August 2. The Strategic Planning Committee is recommending that the compliance filing be made, responding to issues/conditions as follows.

Analysis

Regarding governance, the Commission requires additional clarification regarding the ability of the Board of Directors to act independently. The Strategic Planning Committee is recommending that the Board of Directors approve the changes to the SPP Bylaws necessary to accomplish this requirement. The changes to Sections 4.0 and 5.0 of the Bylaws must be approved by the Membership. The Strategic Planning Committee recommends that the Board of Directors recommend for approval the changes to Sections 4.0 and 5.0 at a special meeting of the Members to be called in conjunction with the July 27 Board of Directors meeting (the Chairman of the Board may call this meeting; however, there will first have to be a vote to waive the 30 day notice requirement in the Bylaws).

In addition, the Commission directed additional expansion of the sectors of the membership for the Members Committee and the Corporate Governance Committee. Specifically, the Members Committee is to have one seat for large retail customers and one seat for small retail customers. A seat is to be added to the Corporate Governance Committee for retail customers. The revised Bylaws include the recommended changes.

Regarding the seams agreement with MISO, a draft agreement is attached. The Strategic Planning Committee recommends that this draft be included in the compliance filing, as directed by the Commission. It is Staff's intention that this be executed with MISO prior to the filing, or in the alternative, that it be filed unexecuted.

Regarding grandfathered agreements, the Regional Tariff Working Group (RTWG) and the Markets and Operations Policy Committee (MOPC) is reviewing the attached tariff revisions provided by regulatory counsel on an expedited basis. It is the recommendation of the Strategic Planning Committee that these changes be included in the compliance filing.

Regarding operational authority, proposed revisions to the Membership Agreement are provided. These revisions are expected to clarify SPP's authority related to day-to-day operations. The Strategic Planning Committee recommends that these revisions be approved.

Regarding the market monitor, the Independent Market Monitor Selection Task Force has selected a vendor. The order expressed some concern about the independence of that monitor, particularly going forward as it has several clients within the electric utility industry. However, the criteria provided by the Commission in the order extend beyond any previously stated requirements, and in fact make it difficult, if not impossible, to find a qualified monitor. Many, but not all, of the Commissions' criteria have been satisfied by the proposed contract with the vendor. The Strategic Planning Committee recommends that the current contract be executed and provided as part of this compliance filing along with a detailed explanation of the reasons all the proposed criteria cannot be accommodated.

Recommendation

The SPC recommends the following:

1) SPP staff should make a compliance filing in the RTO docket by August 2.
2) Acceptance of the SPP Bylaws as presented, including an effective date of July 27, 2004.
3) Inclusion of the current draft of the MISO Joint Operating Agreement in the compliance filing.
4) Approval of tariff changes to Section 39 of the SPP OATT.
5) The SPP Board of Directors should approve the revisions to the SPP Membership Agreement required by the compliance filing, effective.
6) Inclusion of the contract with the Independent Market Monitor in the compliance filing.

Approved: Strategic Planning Committee July 16, 2004

Action Requested: Approve Recommendation

Southwest Power Pool, Inc.

B Y L A W S

4.0 BOARD OF DIRECTORS

4.6 Functioning of the Board of Directors

In reaching any decision and in considering the recommendations of any Organizational Group or task force, the Board of Directors shall abide by the principles in these Bylaws.

4.6.1 Meetings and Notice of Meetings

The Board of Directors shall meet at least three times per calendar year and additionally upon the call of the Chair or upon concurrence of at least four directors. At least fifteen days' written notice shall be given by the President to each director, the Members Committee, and the Regional State Committee of the date, time, place and purpose of a meeting of the Board of Directors, unless such notice is waived by the Board of Directors. Telephone conference meetings may be called as appropriate by the Chair with at least one-day prior notice. Board of Directors' meetings shall include the Members Committee and a representative from the Regional State Committee (as defined in Section ~~5~~7.2) for all meetings except when in executive session; provided however, the failure of representatives of the Members Committee and/or of the Regional State Committee to attend, in whole or in part, shall not prevent the Board of Directors from convening and conducting business, and taking binding votes. The Chair shall grant any Member's request to address the Board of Directors.

5.0 COMMITTEES ADVISING THE BOARD OF DIRECTORS

5.1 Members Committee

5.1.1 Composition and Qualifications

5.1.1.1 Composition

Provided that Membership is sufficient to accommodate these provisions, the Members Committee shall consist of up to ~~16~~ 18 persons. Four representatives shall be investor owned utilities Members; four representatives shall be cooperatives Members; two representatives shall be municipals Members (including municipal joint action agencies); three representatives shall be independent power producers/marketers Members; one representative shall be a state/federal power agencies Member; ~~and~~ two representatives shall be ~~retail/~~alternative power/public interest Members; one representative shall be a large retail customer; and one representative shall be a small retail customer. Representatives will be elected in accordance with Section 5.1.2 of these Bylaws.

6.0 COMMITTEES REPORTING TO THE BOARD OF DIRECTORS

6.1 Corporate Governance Committee

To the extent that the membership allows, the Corporate Governance Committee (CGC) shall be comprised of ~~eight~~ nine members. One representative shall be the President of SPP who will serve as the Chair; the Chairman of the Board, unless his/her position is under consideration, in which case the Vice Chairman of the Board; one representative shall be representative of and selected by investor owned utilities Members; one representative shall be representative of and selected by co-operatives Members; one representative shall be representative of and selected by municipals Members; one representative shall be representative of and selected by independent power producers/marketers Members; one representative shall be representative of and selected by state/federal power agencies Members; ~~and~~ one representative shall be representative of and selected by ~~retail/~~alternative power/public interest Members; and one representative shall be representative of and selected by large/small retail Members.

11 EFFECTIVE DATE AND TRANSITION PROVISIONS

These Bylaws shall become effective ~~May 1~~July 27, 2004 and remain in force thereafter as may be amended. These Bylaws hereby cancel and supersede SPP Bylaws dated ~~June 24, 2003~~May 1, 2004; provided, that these Bylaws do not relieve any Member from any financial obligation incurred thereunder. Binding obligations entered into by authority of Officers or the Board of Directors under these Bylaws are hereby assumed and confirmed as obligations of SPP under these Bylaws.

Joint Operating Agreement
Between the
Midwest Independent Transmission System Operator, Inc.
And
Southwest Power Pool, Inc.

Joint Operating Agreement
Between the
Midwest Independent Transmission System Operator, Inc.
And
Southwest Power Pool, Inc.

ARTICLE I
RECITALS

This Joint Operating Agreement ("Agreement") dated this ____ day of February, 2004, by and between Southwest Power Pool, Inc. ("SPP") an Arkansas not-for-profit corporation having a place of business at 415 North McKinley, #800 Plaza West, Little Rock, AR 72205, and the Midwest Independent Transmission System Operator, Inc. ("MIDWEST ISO"), a Delaware non-stock corporation having a place of business at 701 City Center Drive, Carmel, Indiana 46032. SPP and MIDWEST ISO may be individually referred to herein as "Party" or collectively as "Parties".

WHEREAS, SPP is a North American Electric Reliability Council ("NERC") Regional Reliability Organization and an independent provider of reliability coordination, tariff administration, and scheduling services to its customers and interconnected member electric systems in the Southwest part of the United States;

WHEREAS, SPP has filed a petition with the Federal Energy Regulatory Commission ("FERC") for recognition as a Regional Transmission Organization ("RTO"), and is developing processes and systems to operate energy imbalance, congestion management, and other ancillary service markets in a phased approach;

WHEREAS, the MIDWEST ISO is the RTO that provides operating and reliability functions in portions of the Midwest and Canada. The MIDWEST ISO also administers the MIDWEST ISO Tariff for transmission and other services on its grid, and is developing processes and systems to operate markets to facilitate day-ahead and real-time energy transactions and financially firm transmission rights;

WHEREAS, FERC has ordered each Party to develop mechanisms to address inter-regional coordination;

WHEREAS, on ____, 2004, the Parties entered into the System Operation, Planning and Market Development Memorandum of Understanding ("MOU"), which provides for the establishment of a Seams Agreement Coordinating Committee to develop recommendations on coordination activities that will improve reliability and reduce barriers to electricity trading within the regions and to negotiate a Joint Operating Agreement that will contractually bind the Parties to these coordination activities; and

WHEREAS, in accordance with good utility practice and in accordance with the directives of FERC, the Parties seek to establish exchanges of information and establish or confirm other arrangements and protocols in furtherance of the reliability of their systems and efficient market operations, and to give effect to other matters required by FERC;

NOW, THEREFORE, for the consideration stated herein, and for other good and valuable consideration, the receipt of which hereby is acknowledged, the Parties hereby agree as follows:

ARTICLE II
ABBREVIATIONS, ACRONYMS AND DEFINITIONS

Section 2.1 Abbreviations and Acronyms.

2.1.1 "ATC/AFC" shall mean Available Transfer Capability/Available Flowgate Capability, as those terms are used in the electric utility industry and as AFC is further defined in Section 5.1.7.

2.1.2 "CBM" shall mean Capacity Benefit Margin.

2.1.3 "CIM" shall mean Common Information Model.

2.1.4 "EFOR" shall mean Equivalent Forced Outage Rate.

2.1.5 "EHV" shall mean Extra High Voltage, as defined in Section 11.2.2.

2.1.6 "EMS" shall mean the Energy Management Systems utilized by the Parties to manage the flow of energy within their regions.

2.1.7 "FERC" shall mean the Federal Energy Regulatory Commission or any successor agency thereto.

2.1.8 "FTP" shall mean the standardized file transfer protocol for data exchange.

2.1.9 "FTR" shall mean financial transmission rights.

2.1.10 "GCA" shall mean the Generation Control Area.

2.1.11 "ICCP/ISN" shall mean those common communication protocols adopted to standardize information exchange.

2.1.12 "IDC" shall mean the NERC Interchange Distribution Calculator used for identifying and requesting congestion management relief.

2.1.13 "IDCWG" shall mean the NERC Working Group established to provide advice on the IDC.

2.1.14 "IPSAC" shall mean Inter-regional Planning Stakeholder Advisory Committee.

2.1.15 "JPC" shall mean Joint Planning Committee.

2.1.16 "LCA" shall mean the Load Control Area.

2.1.17 "MMWG" shall mean the NERC working group that is charged with multi-regional modeling.

2.1.18 "MW" shall mean megawatt of power.

2.1.19 "MWh" shall mean megawatt hour of energy.

2.1.20 "NERC" shall mean the North American Electricity Reliability Council or its successor organization.

2.1.21 "OASIS" shall mean the Open Access Same-Time Information System required by FERC for the posting of market and transmission data on the Internet.

2.1.22 "OATI" shall mean the entity that has been retained by NERC, or successor organization, to maintain the IDC system.

2.1.23 "OATT" shall mean the applicable Open Access Transmission Tariff.

2.1.24 "PMAX" shall mean the maximum generator real power output reported in MWs on a seasonal basis.

2.1.25 "PMIN" shall mean the minimum generator real power output reported in MWs on a seasonal basis.

2.1.26 "QMAX" shall mean the maximum generator reactive power output reported in MVARs at full real power output of the unit.

2.1.27 "QMIN" shall mean the minimum generator reactive power output reported in MVARs at full real power output of the unit.

2.1.28 "RCF" shall mean Reciprocal Coordinated Flowgate.

2.1.29 "RTO" shall mean Regional Transmission Organization.

2.1.30 "SACC" means the Seams Agreement Coordinating Committee, established in the Memorandum of Understanding between the Parties.

2.1. 31 "SDX System" shall mean the system used by NERC to exchange system data.

2.1.32 "TLR" shall mean the NERC Transmission Loading Relief Procedures used in the Eastern Interconnection as specified in NERC Operating Policies.

2.1.33 "TRM" shall mean the Transmission Reliability Margin, which is that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

2.1.34 "TTC" shall mean Total Transfer Capability.

Section 2.2 Definitions.

2.2.1 "a & b multipliers" shall mean the multipliers that are applied to TRM in the planning horizon and in the operating horizon to determine non-firm AFC/ATC. The "a" multiplier is applied to TRM in the planning horizon to determine non-firm AFC/ATC. The "b" multiplier is applied to TRM in the operating horizon to determine non-firm AFC/ATC. The "a & b" multipliers can vary between 0 and 1, inclusive. They are determined by individual transmission providers based on network reliability concerns.

2.2.2 "Agreement" shall have the meaning stated in the preamble.

2.2.3 "Available Flowgate Rating" shall have the meaning stated in Section 5.1.8.

2.2.4 "Confidential Information" shall have the meaning stated in Section 18.1.

2.2.5 "Congestion Management Process" means ~~that~~ the document which ~~is~~ will be an ~~Attachment~~ attachment ~~2~~ hereto as it will exist~~s~~ 60 days prior to Phase 2 operations, as described in Section 3.2 of this Agreement, ~~on the Effective Date~~ and as it may be amended or revised from time to time.

2.2.6 "Control Area(s)" shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied.

2.2.7 "Coordinated Flowgates" shall have the meaning stated in Section 6.1.

2.2.8 "Coordinated Operations" means all activities that will be undertaken by the Parties pursuant to this Agreement.

2.2.9 "Coordinated System Plan" shall have the meaning stated in Section 9.3.2.

2.2.10 "Economic Dispatch" shall mean the sending of dispatch instructions to generation units to minimize the cost of reliably meeting load demands.

2.2.11 "Effective Date" shall have the meaning stated in Section 13.1.

2.2.12 "Firm Flow" shall mean the estimated impacts of firm transactions under Network and Point-to-Point service on a particular Coordinated Flowgate.

2.2.13 "Firm Flow Limit" shall mean the maximum value of firm flows an entity can have on a Reciprocal Coordinated Flowgate.

2.2.14 "Flowgate" shall mean a representative modeling of a facility or group of facilities that may act as a constraint to power transfer on the bulk transmission system.

2.2.15 "Foreign Flowgates" shall mean flowgates that are outside of the Parties' regions.

2.2.16 "Intellectual Property" shall mean (i) ideas, designs, concepts, techniques, inventions, discoveries, or improvements, regardless of patentability, but including without limitation patents, patent applications, mask works, trade secrets, and know-how; (ii) works of authorship, regardless of copyright ability, including without limitation copyrights and any moral rights recognized by law; and (iii) any other similar rights, in each case on a worldwide basis.

2.2.17 "Interconnected Reliability Limit" ("IRL") shall mean the value (such as MW, Mvar, Amperes, Frequency, or Volts) derived from, or a subset of, the System Operating Limits, which if exceeded, could expose a widespread area of the bulk electrical system to instability, uncontrolled separation(s) or cascading outages, either under existing system conditions or following a contingency.

2.2.18 "Intermittent Generation" shall mean a resource that cannot be scheduled and controlled to produce the anticipated energy.

2.2.19 "Market" shall mean the energy and/or ancillary services market facilitated by the Parties pursuant to FERC Order No. 2000.

2.2.20 "Market Flows" shall mean the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources within a Market Based Operating Entity's market (excluding tagged transactions).

2.2.21 "Memorandum of Understanding" shall mean that certain predecessor agreement between the Parties to develop this Joint Operating Agreement, dated January 30, 2004.

2.2.22 "MIDWEST ISO" has the meaning stated in the preamble of this Agreement.

2.2.23 "Network Upgrades" shall mean those facilities located beyond the point of interconnection of the generating facility to the transmission grid.

2.2.24 "Notice" shall have the meaning stated in Section 18.10.

2.2.25 "Operating Entity" shall mean an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

2.2.26 "Outages" shall mean the planned unavailability of transmission and/or generation facilities operated by the Parties, as described in Article VII of this Agreement.

2.2.27 "Party" or "Parties" refers to each party to this Agreement or both, as applicable.

2.2.28 "SPP" has the meaning stated in the preamble of this Agreement.

2.2.29 "Priority level of service" shall refer to the appropriate level of service established by NERC in its protocols.

2.2.30 "Reciprocal Coordinated Flowgates" shall have the meaning stated in Section 6.1.

2.2.31 "Reciprocal Entity" shall mean a Party that coordinates the future-looking management of flowgate capacity in accordance with a reciprocal agreement as described in the Congestion Management Process.

2.2.32 "RCF Base Usage" shall mean the long-term firm and network service usage of RCFs.

2.2.33 "Reliability Coordinator" ("RC") shall mean that party approved by NERC to be responsible for reliability for a region.

2.2.34 "SCADA Data" shall mean the electric system security data that is used to monitor the electrical state of facilities, as specified in NERC Policy 4.

2.2.35 "State Estimator" shall mean that computer model that computes the state (voltage magnitudes and angles) of the transmission system using the network model and real-time measurements. Line flows, transformer flows, and injections at the buses are calculated from the known state and the transmission line parameters. The state estimator has the capability to detect and identify bad measurements.

2.2.36 "System Operating Limit" ("SOL") shall mean the value (such as MW, MVar, Amperes, Frequency, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

2.2.37 "Transmission Owner" shall mean any entity defined as such under the SPP OATT, MISO OATT, or MAPP OATT.

2.2.38 "Unit Dispatch Systems" ("UDS") shall mean those dispatch systems utilized by the Parties to dispatch generation units by calculating the most economic solution while simultaneously ensuring that each of the boundary constraints is resolved reliably.

2.2.39 "Voltage and Reactive Power Coordination Procedures" are the procedures under Article XI for coordination of voltage control and reactive power requirements.

Section 2.3 Rules of Construction.

Section 2.3.1 No Interpretation Against Drafter. In addition to their roles as reliability coordinators, and the functions and responsibilities associated therewith, the Parties agree that each Party participated in the drafting of this Agreement and was represented therein by competent legal counsel. No rule of construction or interpretation against the drafter shall be applied to the construction or in the interpretation of this Agreement.

Section 2.3.2 Incorporation of Preamble and Recitals. The Preamble and Recitals of this Agreement are hereby incorporated into the terms and conditions of this Agreement and made a part thereof.

Section 2.3.3 Meanings of Certain Common Words. The word "including" shall be understood to mean "including, but not limited to." The word "Section" refers to the applicable section of this Agreement and, unless otherwise stated, includes all subsections thereof. The word "Article" refers to articles of this Agreement.

Section 2.3.4 Certain Headings. Certain sections of Articles IV and V contain descriptions of the purpose or requirements stated in those sections. These statements of purpose are to provide background information to assist in the interpretation of the requirements. The absence of a stated purpose with respect to any requirement does not diminish the enforceability of the requirement. If a provision in Articles IV and V is not delineated as "purpose," "background," or "definition," it is a requirement.

Section 2.3.5 NERC Policies and Procedures. All activities under this Agreement will meet or exceed the applicable NERC policies or procedures as revised from time to time.

Section 2.3.6 Congestion Management Process. The Congestion Management Process ~~is hereby~~will be incorporated into this Agreement no later than 60 days prior to implementation of Phase 2 operations, as described in Section 3.2 of this Agreement, and in the event there is a conflict between this Agreement and the Congestion Management Process, the Congestion

Management Process prevails. The Congestion Management Process may be amended from time to time upon agreement of the Parties. Any disputes arising under the Congestion Management Process are subject to the dispute resolution provisions contained in Section 14.2 of this Agreement.

Section 2.3.7 **Scope of Application.** Each Party will perform this Agreement in accordance with its terms and conditions with respect to each Transmission Owner for which it administers transmission service and, in addition, each Control Area for which it serves as Reliability Coordinator.

ARTICLE III
OVERVIEW OF COORDINATION AND INFORMATION EXCHANGE

Section 3.1 Ongoing Review and Revisions. The Parties have agreed to the coordination and exchange of data and information under this Agreement to ensure system reliability and efficient market operations as systems exist and are contemplated as of the Effective Date. The Parties expect that these systems and technology applicable to these systems and to the collection and exchange of data will change from time to time throughout the term of this Agreement. The Parties agree that the objectives of this Agreement can be fulfilled efficiently and economically only if the Parties, from time to time, review and as appropriate revise the requirements stated herein in response to such changes, including deleting, adding, or revising requirements and protocols. Each Party will negotiate in good faith in response to such revisions the other Party may propose from time to time.

Section 3.2 Definitions of Phases and Applicable Time Periods. The Parties' coordination and exchange of data and information shall occur in three (3) phases. Phase 1, "Non-Market to Non-Market", shall commence upon execution of this Agreement. Phase 2, "Market to Non-Market," shall commence upon the initiation of a Market within the SPP footprint or the MIDWEST ISO footprint where such a market did not exist prior to the Effective Date and ending when SPP and MIDWEST ISO have initiated Markets. Phase 3, "Market to Market," shall commence when SPP and MIDWEST ISO have implemented Markets and such commencement shall be with respect only to Control Areas included in those Markets. Each phase includes continuation of all elements of prior phases except any elements that, due to initiation of a later phase, are determined by both Parties to be impracticable to perform.

Section 3.3 Elements of Phase 1, Phase 2, and Phase 3.

Section 3.3.1 **Phase 1.** Upon the commencement of Phase 1, Non-Market to Non-Market, the Parties shall commence performance of each of the following elements:

(a) Exchange of data and information between the Parties as described in Articles IV and V;
(b) Calculation of ATC/AFC as described in Article V;
(c) Coordination of Outages as described in Article VII;

(d) Joint operation of emergency procedures as described in Article VIII;
(e) Coordinated regional transmission expansion planning as described in Article IX;
(f) Coordinated scheduling checkouts as described in Article X;
(g) Additions to, or deletions from, the foregoing, to which the Parties may agree from time to time or as ordered by the FERC.

Section 3.3.2 <u>Phase 2</u>. Phase 2, Market to Non-Market, consists of the continuation of all Phase 1 elements (except those that have been completed or due to other circumstances cannot be continued) and, in addition, may consist of the following elements:

(a) Reciprocal coordination of flowgates as described in Article VI and in the Congestion Management Process to be developed;
(b) Implementation of the ~~NERC-approved~~ Congestion Management Process to be developed and as described in Section 12.1.

Section 3.3.3 <u>Phase 3</u>. Phase 3, Market to Market, consists of the continuation of all Phase 1 and Phase 2 elements (except those that have been completed or due to other circumstances cannot be continued) and, in addition, may consist of the following elements:

(a) Generation redispatch and coordination, as described in Articles VIII and XI (pursuant to NERC Policies 5 and 9);
(b) Consistency in calculating energy prices at the market borders as described in Section 12.3.1; and
(c) Additions to, or deletions from Items (a) through (g) of Section 3.3.1 and Items (a) and (b) of Section 3.3.2, to which the Parties may agree from time to time, including agreements prior to initiation of Phase 2 and in accordance with Section 3.1, or as ordered by the FERC.

ARTICLE IV
EXCHANGE OF INFORMATION AND DATA

Section 4.1 Phase 1, Non-Market to Non-Market - Exchange of Operating Data.

Purpose: Sharing data is necessary to facilitate effective coordination of operations and to maintain regional system reliability while assuring the maximum commercial flexibility for market participants.

Requirements: During Phase 1, Non-Market to Non-Market, the Parties will exchange the following types of data and information:

(a) Real-Time and Projected Operating Data;
(b) SCADA Data;
(c) EMS Models;

(d) Operations Planning Data; and
(e) Planning Information and Models.

Each Party shall provide the data identified in items (1) through (5) above to the other Party with respect to all Transmission Owners for which it administers transmission service and Control Areas for which it acts as Reliability Coordinator on the Effective Date and during the term of this Agreement, whether or not such an entity is contemplated as of the Effective Date.

The Parties also shall exchange such information as the Market Monitors of SPP and MIDWEST ISO may request in order to facilitate monitoring in accordance with the Parties' respective FERC-approved market monitoring plans.

To ensure the accuracy of all such data, each Party will designate to the other Party's designated representative a contact to be available twenty-four (24) hours each day, seven (7) days per week, and an alternate contact to act in the absence or unavailability of the primary contact, to respond to any inquiries. With respect to each contact and alternate, each Party shall provide the name, telephone number, e-mail address, and fax number. Each Party may change a designee from time to time by notice to the other Party's designated representative.

The Parties agree to exchange data in a timely manner consistent with existing defined formats or such other formats to which the Parties may agree. If any required data exchange format has not been agreed upon as of the Effective Date, or if a Party determines that an agreed format should be revised, a Party shall give Notice of the need for an agreed format or revision and the Parties will jointly seek to complete development of the format within thirty (30) days of such Notice.

The Parties agree that various components of the data exchanged under this Section is Confidential Information and that:

(a) The Party receiving the Confidential Information shall treat the information in the same confidential manner as its governing documents require it treat the confidential information of its own members and market participants.

(b) The receiving Party shall not release the producing Party's Confidential Information until expiration of the time period controlling the producing Party's disclosure of the same information, as such period is described in the producing Party's governing documents from time to time. The receiving Party will notify and receive consent from the producing Party prior to release of any Confidential Information.

(c) All other prerequisites applicable to the producing Party's release of such confidential information have been satisfied as determined by the producing Party.

Section 4.1.1 Real-Time and Projected Operating Data.

Requirements: The Parties will exchange two categories of operating data: real-time information and projected information, as follows.

(a) The real–time operating information consists of:

- Generation status of the units, as telemetered or as derived from the unit breaker, in each Party's [tariff or reliability coordination] footprint;
- Transmission line status, i.e., status of switching devices associated with each end of the line;
- Control Area demands;
- Selected real-time bus loads;
- Scheduled use of reservations;
- Critical facility limits.

(b) Projected operating information consists of:

- Unit commitment/merit order;
- Generating unit and transmission facilities maintenance schedules;
- Firm purchase and sales;
- The planned and actual operational start-up or change dates for any permanently added, removed or significantly altered transmission segments; and
- The planned and actual start-up testing and operational start-up or change dates for any permanently added, removed or significantly altered generation units.

Section 4.1.2 Exchange of SCADA Data.

Background: NERC Policy 4, Appendix 4B, "Electric System Security Data," describes the types of data that Control Areas are expected to provide, and Reliability Coordinators are expected to share with each other as explained in Policy 4B, "Reliability Coordination – Operational Security Information."

Requirements:

(a) The Parties shall exchange requested SCADA Data via ICCP or ISN.
(b) Each Party shall accommodate, as soon as practical, the other Party's requests for additional existing ICCP/ISN bulk transmission data points,

but in any event no more than one (1) week after the request has been submitted.

(c) Each Party shall respond, as soon as practical, to the other Party's requests for additional, unavailable ICCP/ISN bulk transmission data points, but in any event no more than two (2) weeks after the request has been submitted, with an expected availability target date for the requested data.

(d) The Parties will comply with all governing confidentiality agreements executed by the Parties relating to ICCP/ISN data.

(e) All ICCP data exchanged between the Parties will be exchanged via ISN (NERCNet), unless another exchange platform is otherwise agreed upon.

Section 4.1.3 Models.

Purpose: EMS models contain detailed representations of the transmission and generation configurations within each Party. The Parties depend upon EMS models for reliability coordination and market operations. The regular exchange of models is to ensure that each Party is using current and up-to-date representations of the other Party

Requirements: The Parties will exchange their detailed EMS models once a year in the common information model ("CIM") format adopted by the NERC Data Exchange Working Group, or an otherwise agreed upon format, with monthly updates to be provided as new data becomes available. This yearly exchange will include the ISN data definition files, identification of individual bus loads, seasonal equipment ratings and one-line drawings that will be used to expedite the model conversion process. The Parties will also exchange monthly updates that represent the incremental changes that have occurred to the EMS model since the last monthly update.

Section 4.1.4 Operations Planning Data.

Purpose: Operations planning data is basic information needed to coordinate planning and operations between the Parties.

Requirements: Upon the written request of a Party, the other Party shall provide the information specified in Sections 4.1.4.1 through 4.1.4.12 inclusive, or any components thereof. Each request shall specify the information sought and the frequency upon which it shall be provided, and, with respect to Sections 4.1.4.6, 4.1.4.7, and 4.1.4.8, the reason why provision of the information is necessary to achieve the objectives of this Agreement. A Party receiving a request under this Section shall provide the information promptly to the extent the information is available to the Party. Operations planning data is not generally considered confidential but to the extent any of this data overlaps previously defined operating data in Section 4.1.2, it is considered confidential.

Section 4.1.4.1 - Flowgates:

(a) Flowgate definitions including seasonal TTC, TRM, CBM, a & b multipliers;
(b) Flowgates to be added on demand;
(c) Forced outage rates;
(d) List of Coordinated and Reciprocal Coordinated Flowgates
(e) List of Flowgates to recognize when processing transmission service (if different than list of Coordinated and Reciprocal Flowgates); and
(f) Requirements under Section 5.1.7.

Section 4.1.4.2 - Transmission Service Reservations:

(a) Daily list of all transmission service requests, hourly increment of new requests and status changes on existing requests;
(b) List of reservations to exclude; and
(c) Requirements under Sections 5.1.4 and 5.1.5.

Section 4.1.4.3 – AFC Data:

Each Party will meet a minimum periodicity for calculating and posting AFCs. The minimum periodicity depends on the service being offered. The following AFC data will be provided:

(a) Hourly for first seven (7) days posted at a minimum, once per hour;
(b) Daily for days eight (8) through thirty-one (31) posted at a minimum, once per day; and
(c) Monthly for months two (2) through sixteen (16) posted at a minimum, once per month.

Section 4.1.4.4 - Load Forecast:

(a) Hourly for next seven (7) days, daily for days eight (8) through thirty-one (31), and monthly for months two (2) through sixteen (16) submitted once a day;
(b) Indicate whether this is a Control Area or sub-Control Area (by company within the Control Area) forecast;
(c) Indicate whether this includes transmission system losses, and if it does, indicate what the percent losses are;
(d) Identify non-conforming loads;
(e) Indicate how municipal entities, cooperatives and other entity loads are treated. Indicate whether they are included in the forecast. If so, indicate the total load or net load after removing other entity generation; and
(f) Requirements under Section 5.1.6.

Section 4.1.4.5 - Generator Data:

(a) Unit owner, bus location in model;
(b) Seasonal ratings, PMIN, PMAX, QMIN, QMAX;
(c) Station auxiliaries to extent gross generation has been reported;
(d) Regulated bus, target voltage and actual voltage;
(e) Planned maintenance;
(f) EFOR; and
(g) Real-time output (MW & MVAR) with net generation after being reduced for station auxiliaries preferred.

Section 4.1.4.6 – Jointly-Owned Units:

(a) Deemed ownership shares;
(b) Treatment as pseudo tie or dynamic/static schedules;
(c) Rules for sharing output between joint owners of those units that affect the operating seam between the Parties; and
(d) Transmission arrangements between joint owners.

Section 4.1.4.7 - Pumped Storage Units:

(a) Hourly unit's commitment for next 7 days indicating unit output in generation mode and unit input in pumping mode;
(b) Ownership shares for each mode (if jointly owned unit);
(c) Restricted usage times in each mode and time lapse to switch between pumping mode and generation mode; and
(d) Indicate whether unit input during pumping mode has been included in Control Area hourly load forecast.

Section 4.1.4.8 - Intermittent Generation:

(a) Accredited capacity;
(b) Hourly unit commitment for next 7 days;
(c) Planned maintenance;
(d) Whether aggregated generation or generation by piece of equipment;
(e) Whether all output is tagged; and
(f) EFOR.

Section 4.1.4.9 - Control Area Net Interchange from Reservations and Tags:

(a) Any grandfathered agreements that do not appear in OASIS; and
(b) If tags and reservations can no longer be used to develop Control Area or zone net interchange, hourly unit commitment information will be needed for all generators in the Control Area/zone.

Section 4.1.4.10 - Dynamic Transfers:

(a) List of dynamic transfers;
(b) Identification of each dynamic transfer as a dynamic schedule or pseudo-tie, as defined by NERC;
(c) Requirements under Section 5.1.

Section 4.1.4.11 - List of Controllable Devices:

(a) ~~(~~List of controllable devices that may include: phase shifters, DC lines, and back-to-back AC/DC converters; and
(b) Operating practices of the controllable devices.

Section 4.1.4.12 - Generation and Transmission Outages:

(a) Generation outages that are planned or forecast, as soon as practicable after they are identified, including all data specified in Section 5.1.1;
(b) Transmission outages that are planned or forecast, as soon as practicable after they are identified, including all data specified in Section 5.1.3; and
(c) Prompt notification of all forced outages of both generation and transmission resources.

Section 4.2 Phase 2 and Phase 3, Market to Non-Market and Market to Market - Exchange of Operating Data.

Requirements: Prior to the initiation of Phases 2 and 3, Market to Non-Market and Market to Market, the Parties shall confer regarding the need to exchange any information other than that identified for exchange in Phase 1 in Section 4.1, and shall make agreements for exchange of such information during Phases 2 and 3 as is necessary to achieve the objectives of this Agreement.

Section 4.3 Cost of Data and Information Exchange.

Requirements: Each Party shall bear its own cost of providing information to the other Party pursuant to Sections 4.1 and 4.2.

ARTICLE V
ATC/AFC CALCULATIONS

Section 5.1 ATC/AFC Protocols - Phase 1, Non-Market to Non-Market.

Purpose: The calculation of Total Transfer Capability ("TTC") and Available Transfer Capability ("ATC") is a forecast of transmission capacity that may be available for use by transmission customers. Use of transmission capacity in one system can impact the loadings, voltages and stability of neighboring systems. Because of this interrelationship, neighboring entities must exchange pertinent data for each entity to determine the TTC and ATC/AFC values for its own transmission system. The exchange of data related to calculation of TTC and ATC is necessary to assure reliable coordination, and also to permit either Party to determine if, due to lack of transmission capacity, it must refuse a transmission reservation in order to avoid potential overloading of facilities.

As of the Effective Date, the Parties use the NERC SDX System to exchange the status of generators rated greater than 150 MW, outages of all interconnections and other transmission facilities operated at greater than 230 kV, and peak load forecasts. This system has the capability to house daily data for the next seven (7) days, weekly data for the next month, and monthly data for the next year. Continued use of this tool, and associated commitments under this Agreement, will assure the Parties' ability to make reliable calculations efficiently.

Section 5.1.1 <u>Generation Outage Schedules</u>.

Requirements: Each Party shall provide the other with projected status of generation availability over the next twelve (12) months, or more often if information becomes available. The Parties will update this data no less than once daily for the full posting horizon and more often as required by system conditions. The data will include complete generation maintenance schedules and the most current available generator availability data, such that each Party is aware of each "return date" of a generator from a scheduled or forced outage. If the status of a particular generator of less than 150 MW is used within a Party's TTC/ATC/AFC calculation, the status of this unit shall also be supplied.

Section 5.1.2 <u>Generation Dispatch Order</u>.

Purpose: Dispatch information combined with unit availability information permits each Party to develop a reasonably accurate dispatch for any modeled condition. This methodology is more advantageous than scaling all available generation to meet generation commitments within an area and then increasing all generation uniformly to model an export, or uniformly decreasing all generation to model an import. While excluding nuclear generation or hydro units from this scaling would provide some level of refinement, this approach is inadequate to identify transmission constraints and determine rational TTC/ATC/AFC values. On the other extreme, although economic data could be shared to allow an economic dispatch to be determined for each level of generation commitment, this level of refinement is generally unnecessary, and the data is likely to be considered confidential by the generation owners, and therefore unavailable. The exchange of typical generation dispatch order or generation participation factors of all units on a control area basis and other data under this Agreement will permit each Party to appropriately model future transmission system conditions.

Requirements: As necessary to permit a Party to develop a reasonably accurate dispatch for any modeled condition, each Party will provide the other Party with a typical generation dispatch order or the generation participation factors of all units on an affected control area basis. The generation dispatch order will be updated as required by changes in the status of the unit; however, a new generation dispatch order need not be provided more often than prior to each peak load season.

Section 5.1.3 Transmission Outage Schedules.

Requirements: Each Party will provide the other Party with the projected status of transmission outage schedules above 230 kV over the next twelve (12) months or more if available. This data shall be updated no less than once daily for the full posting horizon and more often as required by system conditions. The data will include current, accurate and complete transmission facility maintenance schedules, including the "outage date" and "return date" of a transmission facility from a scheduled or forced outage. If the status of a particular transmission facility operating at voltages less than 230 kV is critical to the determination of TTC and ATC/AFC of a Party, the status of this facility will also be provided.

Section 5.1.4 Transmission Interchange Schedules

Purpose: Because interchange schedules impact the short-term use of the transmission system, exchange of schedule data is necessary to determine the remaining capacity of the transmission system as well as to determine the net impact of loop flow.

Requirements: Each Party will make available to the other its interchange schedules, as required to permit accurate calculation of TTC and ATC/AFC values. Due to the high volume of this data, the Parties shall either post this data to an FTP site for downloading by the other Party as required by its own process and schedules, or shall request NERC to modify the IDC to allow for selected interrogation by the Parties

Section 5.1.5 Transmission Service Requests.

Purpose: Beyond the operating horizon, the impacts of existing transmission service requests are also necessary for the calculation of TTC and ATC/AFC for future time periods. Inasmuch as a transmission reservation is a right to use and not an obligation to use the transmission system, there is no certainty that any particular reservation will result in a corresponding interchange schedule. This is especially true considering that the *pro forma* tariff allows firm service on a given path to be redirected as non-firm service on any other path. In addition, the ultimate transmission customer may not have, at a given time, purchased all transmission reservations on a particular source-to-sink path. A further complication is that the duration or firmness of the one portion of the reservation may not be the same as the remaining portion. Since the portions of a source to sink reservation may not be able to be associated prior to scheduling, double counting in the ATC/AFC determination process is a possibility. It is acknowledged that reservations respecting one Party are not required to be incorporated into transmission models developed by the other Party.

Requirements:

(a) Each Party will make available to the other Party, on an FTP site, actual transmission service request information for integration into each Party's TTC/ATC/AFC determination process.

(b) Each Party will develop practices for modeling transmission service requests, including external requests, and netting practices for any allowance of counterflows created by reservations in electrically opposite directions. Each Party will provide the other Party with the procedures developed and implemented to model intra-Party requests, requests on external parties, and reservation netting.

(c) Each Party shall also create and maintain a list of reservations from its OASIS that should not be considered in ATC/AFC calculations. Reasons for these exceptions include, for example, grandfathered agreements that grant access to more transmission than is necessary for the related generation capacity and unmatched intra-Party partial path reservations. If a Party does not include it in its own evaluation, it should be excluded in other Parties' analysis.

Section 5.1.6 Load Data.

Requirements: The Parties will exchange peak load data for each period (*e.g.*, daily, weekly, and monthly). Since, by definition, peak load values may only apply to one (1) hour of the period, additional assumptions must be made with respect to load level when not at peak load conditions. For the next seven (7) day horizon, the Parties shall either supply hourly load forecasts or they shall supply daily peak load forecasts with a load profile. All load forecasts will be provided on a Control Area basis, with further granularity provided to reflect load forecasts by company within the Control Area.

Section 5.1.7 Calculated Firm and Non-firm Available Flowgate Capability.

Definitions: The Available Flowgate Capability ("AFC") is the applicable rating of the flowgate less the projected loading across the particular flowgate less Transmission Reliability Margin and Capacity Benefits Margin. The Firm AFC is calculated with only the appropriate firm transmission service reservations (or interchange schedules) in the model, including recognition of all roll-over transmission service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

Purpose: Data exchange is required to determine if a transmission service reservation (or interchange schedule) will impact flowgates to an extent greater than the (firm or non-firm) AFC and procedures are necessary to assure that each Party respects the other Party's flowgates.

Requirements:

(a) The Parties will exchange Firm and Non-firm AFC for all relevant flowgates.

(b) Each Party will accept or reject transmission service requests based upon projected loadings on their own flowgates as well as the loadings on Foreign Flowgates. Each Party will limit approvals of transmission service reservations, including roll-over transmission service, so as to not exceed the sum of the thermal capabilities of the tie lines that interconnect the Parties, provided that firm transmission service customers with terms of one year or longer retain the rollover rights and reservation priority granted to them under the applicable Party's OATT, and further provided that if explicitly stated in the applicable service agreement, a Party may limit rollover rights for new long-term firm service if there is not enough ATC to accommodate rollover rights beyond the initial term.

Section 5.1.8 Available Flowgate Rating.

Definition: The Available Flowgate Rating is the maximum amount of power that can flow across that interface without overloading (either on an actual or contingency basis) any element of the flowgate. The flowgate rating is in units of megawatts. If the flowgate is voltage or stability limited, a megawatt proxy is determined to ensure adequate voltages and stability conditions.

Requirements: The Parties will exchange (seasonal, normal and emergency) Available Flowgate Ratings as well as all limiting conditions (thermal, voltage, or stability). The Parties will update this information in a timely manner as required by changes on the transmission system.

Section 5.1.9 Identification of Flowgates.

Requirements: Each Party shall consider in its TTC and ATC/AFC determination process all flowgates: (i) that may initiate a TLR event, or (ii) as mutually agreed between the Parties. As determined in accordance with Section 3 of the Congestion Management Process, flowgates that have a response factor equal to or greater than the distribution factor cut-off must be included in the evaluating Party's model to the extent inclusion is practical. The Parties shall use the response factor cut-off that the owning/operating Party uses for its flowgate in its AFC determination efforts.

Section 5.1.10 Configuration/Facility Changes (for power system model updates).

Requirements:

(a) A mechanism will be instituted between the Parties to ensure that all significant system changes of a neighbor are incorporated in each Party's TTC/ATC/AFC calculation model, within sixty (60) days after the Effective Date of this Agreement. Although this information and a host of very detailed data are included in the MMWG cases, this data exchange mechanism will address the 'major' changes that should be included in the TTC/ATC/AFC calculation models in a more timely manner. This type of data change will be similar to the 'New Facilities' Listings usually included in inter-regional reports; however, explicit modeling information will need to be supplied along with the listing. This data exchange will occur no less often than prior to each peak load season.

(b) In addition, the Parties agree to exchange TTC/ATC/AFC calculation models of their transmission systems as soon as mechanisms can be established to facilitate this exchange.

Section 5.1.11 Dynamic Schedule Flows.

Requirements: Each Party agrees to provide the other Party with the actual amount and future projection of dynamic schedule flows commencing no later than sixty (60) days from the signing of this Agreement. All dynamic schedule flows and tags will be submitted in accordance with NERC policy and procedures.

Section 5.2 ATC/AFC Protocols – Phases 2 and 3, Market to Non-Market and Market to Market. The Parties will address any appropriate revisions to the requirements set forth in Section 5.1.1 through Section 5.1.11 that may arise in the implementation of Phases 2 and 3.

ARTICLE VI
RECIPROCAL COORDINATION OF FLOWGATES

Section 6.1 Reciprocal Coordination of Flowgates Operating Protocols - Phase 2, Market to Non-Market. As used in this Article~~ and the Congestion Management Process~~:

Parties will develop and agree upon a Congestion Management Process by no later than 60 days prior to Phase 2 operations to accomplish the following enhanced coordination principles required when either Party implements a market.~~"Coordinated Flowgate" or CF shall mean a Flowgate impacted by an Operating Entity as determined by one of the four studies detailed in Section 3 of the Congestion Management Process. For a Market-Based Operating Entity, these Flowgates will be subject to the requirements under the congestion management portion of the Congestion Management Process (Sections 4 and 5). A Coordinated Flowgate may be under the operational control of a third party.~~

~~"Reciprocal Coordinated Flowgate" or RCF shall mean a Coordinated Flowgate with respect to which a reciprocal agreement has been written and to which reciprocal coordination procedures as defined in the Congestion Management Process apply. A RCF is either (1) a CF affected by the transmission of energy by both Parties, or (2) a Flowgate, which both Parties mutually agree should be a Coordinated Flowgate, and for which reciprocal coordination will occur.~~

~~A "Reciprocal Coordinated Flowgate" or "RCF" is either (1) a CF affected by the transmission of energy by both Parties, or (2) a Flowgate upon which both Parties mutually agree reciprocal coordination will occur. As with a CF, a RCF may be under the operational control of one of the Parties, or may be under the operational control of a third party.~~

6.1.1 ~~**Reciprocal Coordinated Flowgates.** In order to coordinate congestion management proactively, each Party agrees to respect the other Party's determinations of AFC/ATC and calculations of firmness for real-time operations applicable to the Party's CFs. Additionally, each Party agrees to respect the Allocations defined by the Reciprocal Allocation Process set forth in the Congestion Management Process.~~

~~**6.1.2**~~ **Coordination Process for Reciprocal Coordinated Flowgates.** In order to coordinate congestion management proactively, each Party agrees to respect the other Party's determinations of AFC/ATC and calculations of firmness for real-time operations. The Parties will establish and finalize the process and timing for ~~exchanging~~ enhancing their respective ATC/AFC calculations pursuant to the Congestion Management Process to be developed~~and Firm Flow calculations/allocations with respect to all RCFs~~. Further, the process will allocate Flowgate capacity on a future-looking basis, including the allocation of

Firm and Non-Firm Capability for use in both internal dispatch and selling of transmission service. The Congestion Management Process will set~~s~~ forth the procedure for reciprocal coordination. ~~For any Flowgate comprised of one or more controllable devices, the historically determined Firm Flow on the Flowgate and any allocated rights to that Flowgate under this process are subject to the operating practices of the controllable device. To the extent the controllable device is able to maintain scheduled flows, there are no parallel flows on the Flowgate and a historical allocation based on parallel flows will not occur. In this instance, the use of the Flowgate will be limited to entities that have arranged transmission service across the interface formed by the controllable device. To the extent the controllable device cannot maintain scheduled flows, there will be a historical allocation on the Flowgate based on parallel flows.~~

6.1.3 Real-Time Operations Process. The Parties' capabilities and real time actions ~~shall~~ will be governed by and in accordance with the Congestion Management Process to be developed.

Section 6.2 Costs Arising From Reciprocal Coordination of Flowgates During Phase 2 and Phase 3. In the event redispatch occurs in order to coordinate congestion management under Section 6.1 or subparts thereof, during Phase 2, Market to Non-Market, including redispatch necessary to respect the other Party's flowgate, or during Phase 3, Market to Market, as set forth in Article XII, the Party responsible for the flow that required the redispatch shall bear the costs of the redispatch to the extent the costs may be recovered under the Party's OATT.

Section 6.3 Transmission Capacity for Reserve Sharing. Each Party shall make transmission capacity available for reserve sharing by either redispatching its flowgates or holding TRM for generation outages in the other Party's system. The Party responsible for making transmission capacity available for the reserve sharing obligation shall bear the costs of the redispatch to the extent the costs may be recovered under such Party's OATT.

Section 6.4 Sharing Contract Path Capacity. In recognition that the Joint and Common Market is expected to eliminate distinct MIDWEST ISO contract path limits versus SPP contract path limits and in recognition that the sharing of flowgate capacity on a historical usage basis is the first step toward the elimination of distinct contract path limits, the MIDWEST ISO and SPP have agreed to the following phased approach to the elimination of such contract path limits:

(a) When the MIDWEST ISO and SPP commence operation of energy markets, the sharing of contract path capacity where the MIDWEST ISO and SPP have existing contract path capacity to the same entity will continue to exist. The MIDWEST ISO and SPP may need to resolve any coordination issues such that the combined contract capacity is not exceeded by the operation of the two markets. This phase will still not open up any new paths for the Parties.

(b) When a Joint and Common Market exists between the MIDWEST ISO and SPP as is expected, the sharing of contract path capacity between the MIDWEST ISO and SPP will occur on a complete basis. All physical connections to the combined MIDWEST ISO and SPP RTOs will be available for use by the market. Whether the physical path connections are within the MIDWEST ISO or SPP will not affect a customer's participation in the market. Only actual physical limitations will impact how the customer is able to use these connections to the market.

ARTICLE VII
COORDINATION OF OUTAGES

Section 7.1 Coordinating Outages Operating Protocols. The Parties will jointly develop protocols for coordinating transmission and generation outages to ensure reliability and to promote optimally efficient market operations. The Parties agree to the following with respect to transmission and generation outage coordination.

Section 7.1.1 Exchange of Transmission and Generation Outage Schedule Data. Upon a Party's request, the projected status of generation and transmission availability will be communicated between the Parties, subject to data confidentiality agreements. All available information regardless of scheduled date will be shared. The Parties shall exchange the most current information on proposed outages and provide a timely response on anticipated impacts of proposed outages.

The Parties agree that this information will be shared promptly upon its availability, but no less than daily and more often as required by system conditions. The Parties shall jointly develop a common format for the exchange of this information. The information shall include the owning Party's facility name; proposed outage start date and time; proposed facility return date and time; date and time when a response is needed from the impacted Party to modify the proposed schedule; and any other information that may be relevant to the reliability assessment.

Each Party will also provide information independently on approved and anticipated outages formatted as required for the NERC SDX System.

Section 7.1.2 Evaluation and Coordination of Transmission and Generation Outages. The Parties will analyze planned critical facility maintenance to determine its effects on the reliability of the transmission system. Each Party's outage analysis will consider the impact of its critical outages on the other Party's system reliability, in addition to its own.

On a daily basis, the operations planning staff of each Party shall jointly discuss any outages to identify potential impacts. These discussions should include an indication of either concurrence with the outage or identify significant impact due to the outage as scheduled. Neither Party has the authority to cancel the other Party's outage (except transmission facilities interconnecting the two Parties' transmission systems). However, the Parties will work together to resolve any identified outage conflicts. Consideration will be given to outage submittal times and outage criticality when addressing outage conflicts. If outage analysis indicates unacceptable system conditions, the Parties will work with one another and the facility owner(s), as necessary, to provide remedial steps to be taken in advance of proposed maintenance. If an operating procedure cannot be developed and a change to the proposed schedule is necessary based on significant impact, the Parties shall discuss the facts involved and make every effort to act on behalf of the other Party to effect the requested schedule change. If this change cannot be accommodated, the Party with the outage shall notify the impacted Party. A request to adjust a proposed outage date must include, identification of the facility(s) overloaded, and identify a similar time frame of more appropriate dates/times for the outage.

The Parties will notify each other of emergency maintenance and forced outages as soon as possible after these conditions are known. The Parties will evaluate the impact of emergency and forced outages on the Parties' systems and work with one another to develop remedial steps as necessary.

Outage schedule changes, both before or after the work has started, may require additional review. Each Party will consider the impact of these changes on the other Party's system reliability, in addition to its own. The Parties will contact each other as soon as possible if these changes result in unacceptable system conditions and will work with one another to develop remedial steps as necessary.

ARTICLE VIII
JOINT OPERATION OF EMERGENCY PROCEDURES

Section 8.1 Emergency Operating Procedures. Joint emergency procedures are essential due to the highly dependent nature of facilities under different authorities. The Parties are committed to reliable operation of the transmission system under normal conditions, and will work closely together during emergency situations that place the stability of the transmission system in jeopardy.

In the event either Party declares a system emergency with respect to its system, the Parties will coordinate respective actions to provide immediate relief. The Parties will notify each other of emergency maintenance and forced outages as soon as possible after the conditions are known. The Parties will evaluate the impact of emergency and forced outages on the Parties' systems and work with one another to develop remedial steps as necessary

In the interest of maintaining system stability and providing prompt response to problems that may arise, the Parties agree that in situations where there is an actual Interconnected Reliability Limit ("IRL") violation and/or the system is on the verge of imminent collapse, and when there is already an existing Emergency Procedure or Operating Guide, both Parties and the affected operating entity will communicate and coordinate simultaneously via conference calls. Subsequent to such anomalous operations, the requesting Party will file a lessons learned report for the Parties and operating entities. This lesson learned report may assist in improving operations so that future operations will be more proactive; thereby, avoiding such abnormal communications/procedures.

The Parties will work together and with the Control Areas under their purview to jointly develop and commit to additional emergency procedures as the need for such procedures arises.

TLR Level 6 may be implemented when, in the judgment of either Party, the system is in an emergency condition that is characterized by the potential, either imminently or for the next contingency, for system instability or cascading, or for equipment loading or voltages significantly beyond applicable operating limits, such that stability of the system cannot be assured, or to prevent a condition or situation that in the judgment of a Party is imminently likely to endanger life or property. In the event that it becomes necessary for either Party to issue a TLR Level 6 for a flowgate that is in close electrical proximity to both of the Parties' areas, both Parties will take action(s) in kind to address the situation that prompted the TLR. These actions may include:

(a) Curtailment of equivalent amounts of firm point-to-point transactions within both Parties;

(b) Redispatching of generation within both Parties; and

(c) Load shedding within both Parties.

In situations where an actual IRL violation exists and the transmission system is currently, or for the next contingency would be, on the verge of imminent collapse, and there is not an existing Emergency Procedure or Operating Guide, the Parties will receive and carry out the instruction of the affected Party, or communicate the instruction to the affected entity within their own boundary, or utilize conference call capabilities to allow simultaneous coordination/communication between the Parties and the affected entity.

No delay shall take place during the event, except in instances where the requested action will result in a more serious condition on the transmission system, or instances where, in the judgment of either Party, the requested action is imminently likely to endanger life or property. Financial considerations shall have no bearing on actions taken to prevent the collapse of the transmission system. All occurrences of this kind may be reviewed by either or both Parties after the fact.

In a situation where a System Operating Limit ("SOL") violation exists within the regions of the Parties, or for the next contingency would exist, the Parties will work together as necessary, following good utility practices, and take action in kind as required to address the situation.

As the Reliability Coordinator for each respective region, each Party has the responsibility and authority to coordinate with the other Party and direct emergency action on the part of generation or transmission to protect the reliability of the network and shall do so if required to resolve emergency conditions in the other Party's region.

Section 8.1.1 Power System Restoration. Effective restoration procedures require coordination and communication at all levels of the Parties' organizations and their membership. During power system restoration, the Parties will coordinate their actions with each other, as well as with other Reliability Coordinators, in order to restore the transmission system as safely and efficiently as possible. In order to enhance restoration operations between the Parties, both Parties will conduct annual coordinated restoration drills. These drills will stress cooperation and communication so that both Parties are positioned to better assist the other in a real restoration

Section 8.1.2 Joint Voltage Stability Operating Protocol. Voltage stability or collapse problems have the potential to cause cascading outages and therefore must be closely coordinated to maintain reliable operations. The Parties were formed to have a regional perspective that looks beyond the boundary of a single control area. As such, the Parties will coordinate operations in accordance with good utility practice in order to maintain stable voltage profiles throughout the respective Party's zones of operations.

Section 8.1.3 Conservative Operations. When any one Party identifies an overload/emergency situation that may impact the other Party's system and the other Party's results/systems do not observe a similar situation, both Parties will operate to the most conservative result until the Parties can identify the reasons for these difference(s).

Section 8.2 Compensation for Compliance with Emergency Procedures. Each Party is to bear its own costs of compliance with emergency energy procedures, except as the applicable Tariff may otherwise require. If a Party is required to purchase emergency energy in order to address the flow of the other Party, then the other Party shall be required to provide compensation.

ARTICLE IX
COORDINATED REGIONAL TRANSMISSION EXPANSION PLANNING

Section 9.1 Committees.

Section 9.1.1 Joint Planning Committee. The Seams Agreement Coordinating Committee ("SACC") shall form, as a subcommittee, a Joint Planning Committee ("JPC"), comprised of representatives of the Parties' respective staffs in numbers and functions to be identified from time to time. Each Party shall have the right, every other year, to designate a Chairman of the JPC to serve a one-year calendar term, except that the term of the first Chairman shall commence on the Effective Date and end December 31, 2004. The SACC shall designate the first Chairman. The Chairman shall be responsible for the scheduling of meetings, the preparation of agendas for meetings, and the production of minutes of meetings. The JPC shall coordinate the coordinated system planning under this Agreement, including the following:

(a) Prepare and document detailed procedures for the development of power system analysis models. At a minimum, and unless otherwise agreed, the JPC shall develop common power system analysis models to perform coordinated systems planning, as well as models for power flow analyses, short circuit analyses, and stability analyses. For studies of interconnections in close electrical proximity at the boundaries between the systems of the parties, the JPC will direct the performance of a detailed review of the appropriateness of applicable power system models.

(b) Prepare, on a regular basis, a Coordinated Systems Plan as required under Section 9.3.5.

(c) Coordinate all planning activities under this Article IX, including the exchange of data provided under this Article.

(d) Maintain and share the cost of maintaining an Internet site and e-mail or other electronic lists for the communication of information related to the coordinated planning process.

(e) Meet at least a semi-annually to review and coordinate transmission planning activities.

(f) Support the review by any federal or provincial agency of elements of the Coordinated System Plan.

(g) Support the review by multi-state entities to facilitate the addition of inter-state transmission facilities.

(h) Establish working groups as necessary to provide adequate review and development of the regional plans.

(i) Establish a schedule for the rotation of responsibility for data management, coordination of stakeholder meetings, coordination of analysis activities, report preparation, and other activities.

(j) Oversee an annual meeting of the Parties' system operations, market operations, and system planning personnel (such personnel as the Parties may designate for the meeting), to review the issues impacting the coordination of these functions as they impact long range planning and the coordination of planning between the systems.

Section 9.1.2 <u>Inter-regional Planning Stakeholder Advisory Committee</u>. The Parties shall form an Inter-regional Planning Stakeholder Advisory Committee ("IPSAC"). The IPSAC shall facilitate stakeholder review and input into coordinated system planning for the development of the Coordinated System Plan. IPSAC members shall be members of the MIDWEST ISO Planning Advisory Committee, or its successor, and the SPP Operations Policy Committee, or its successor. Other stakeholders shall be permitted to become members, including stakeholders created by change of geographic scope. The IPSAC will meet no less frequently than prior to the start of each cycle of the coordinated planning process, during the development of the Coordinated System Plan, and upon completion of the Plan to review final results.

Section 9.2 Data and Information Exchange. In support of coordinated system planning , each Party shall provide the other with the following data and information. Unless otherwise indicated, such data and information shall be provided annually.

(a) Data required for the development of load flow cases, short-circuit cases, and stability cases, including ten year load forecasts, including all critical assumptions that are used in the development of these cases.

(b) Fully detailed planning models (up to the next ten (10) years) on an annual basis and monthly updates that reflect system enhancement changes or other changes, as they occur.

(c) The regional plan document produced by the Party, any long-term or short-term reliability assessment documents produced by the Party, and any operating assessment reports produced by the Party.

(d) The status of expansion studies, system impact studies and generation interconnection studies, such that each Party has knowledge that a commitment has been made to a system enhancement as a result of any such studies.

(e) Transmission system maps for the Party's bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two systems.

(f) Contingency lists for use in load flow and stability analyses, including lists of all single contingency events and multiple facility tower line contingencies, as well as breaker diagrams for the portions of the Party's transmission system that are relevant to the coordination of planning between the two systems.

(g) The timing of each planned enhancement, including estimated completion dates and project mobilization schedules, and indications of the likelihood a system enhancement will be completed and whether the system enhancement should be included in system expansion studies, system impact studies and generation interconnection studies, and all related applications for regulatory approval and the status thereof. This information shall be provided annually and from time to time upon changes in status.

(h) Monthly identification of interconnection requests that have been received and any long-term firm transmission services that have been approved that may impact the operation of a Party's system in a manner that affects the other Party's system.

(i) Quarterly, the status of all interconnection requests that have been identified.

(j) Information regarding long-term firm transmission services on all interfaces relevant to the coordination of planning between the systems.

(k) Such other data and information as is needed for each Party to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other Party.

(l) Load flow and short-circuit data initially will be exchanged in PSS/E format. To the extent practical the maintenance and exchange of power system modeling data will be implemented through databases. When feasible, transmission maps and breaker diagrams will be provided in an electronic format agreed upon by the Parties. Formats for the exchange of other data will be agreed upon by the Parties from time to time.

Section 9.3 Coordinated System Planning. The primary purpose of coordinated transmission planning is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, or enhance the competitiveness of electricity markets.

Section 9.3.1 Single Party Planning. Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its agreements and open access transmission tariff. Such planning shall conform to applicable reliability requirements of NERC, applicable regional reliability councils, or any successor organizations, and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report and document the procedures, methodologies, and business rules that are utilized in preparing and completing this transmission planning report. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, the identification of proposed transmission system enhancements that may affect the Parties' respective systems.

Section 9.3.2 Coordinated System Plan. The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan. The Coordinated System Plan shall have as input the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. Construction of upgrades that are identified as necessary in the Coordinated System Plan shall be under the terms of the Transmission Owner Agreements of the Parties, applicable to the construction of upgrades identified in the expansion planning process.

Section 9.3.3 Analysis of Interconnection Requests. In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. Coordination of studies and upgrades will include the following:

(a) Upon the posting to the OASIS of a request for interconnection, the Party receiving the request ("direct connect system") will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the directly connected system will notify the other Party and convey the information provided in the posting.

(b) If the potentially impacted Party determines that its system may be materially impacted by the interconnection, that Party will contact the direct connect system and request participation in the applicable interconnection studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party, who will perform the studies. The Parties will strive to minimize the costs associated with the coordinated study process.

(c) Any coordinated studies will be performed in accordance with the study timeline requirements of the applicable generation interconnection procedures of the direct connect system. The potentially impacted Party will comply with this schedule.

(d) The potentially impacted Party may participate in the coordinated study either by taking responsibility for performance of studies of its system, or by providing input to the studies to be performed by the direct connect system. The study cost estimates indicated in the study agreement between the direct connect system and the interconnection customer will reflect the costs and the associated roles of the study participants including the potentially impacted Party. The direct connect system will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(e) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts to the potentially impacted Party.

(f) If the results of the coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such network upgrades in the system impact study prepared for the interconnection customer.

(g) Requirements for construction of, and the reimbursement of costs related to, such Network Upgrades will be under the terms and conditions of the potentially impacted system and consistent with applicable federal or provincial regulatory policy.

(h) Each Party will maintain a separate interconnection queue. The JPC will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. The JPC will post this listing on the Internet site maintained for the communication of information related to the coordinated planning process. The Internet site will contain links to the web sites of each Party where individual interconnection study results will be maintained.

Section 9.3.4 Analysis of Long Term Firm Transmission Service Requests. In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. Coordination of studies will include the following:

(a) The Parties will coordinate the calculation of ATC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.

(b) Upon the posting to the OASIS of a request for service, the Party receiving the request will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the request will notify the other Party and convey the information provided in the posting.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, that Party will contact the Party receiving the request and request participation in the applicable transmission service studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to maximize the cost efficiency of the coordinated study process. The JPC will develop screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the study timeline requirements of the applicable transmission service procedures of the Party receiving the request. The potentially impacted Party will comply with this schedule.

(e) The potentially impacted system may participate in the coordinated study either by taking responsibility for performance of studies of their system, or by providing input to the studies to be performed by the Party receiving the request. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the request will collect from the transmission service customer and forward to the potentially impacted system the costs incurred by the potentially impacted systems associated with the performance of such studies.

(g) If the results of a coordinated study indicate that network upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the system receiving the request will identify the need for such network upgrades in the system impact study prepared for the transmission service customer.

(h) Requirements for the construction of such Network Upgrades will be under the terms and conditions of the potentially impacted system and consistent with applicable federal, state, or provincial regulatory policy.

Section 9.3.5 Development of the Coordinated System Plan. Each Party agrees to assist in the preparation of a Coordinated System Plan applicable to the Parties' systems. Each Party's annual transmission planning reports will be incorporated into the Coordinated System Plan, however, neither Party shall have the right to veto any planning of the other Party nor shall either Party have the right, under this Article, to obtain financial compensation due to the impact of another Party's plans or additions. The IPSAC will have an opportunity to review and comment before the Coordinated System Plan is finalized:

(a) Integrate the Parties' respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation or merchant transmission projects) and transmission system upgrades identified jointly by the Parties, together with alternatives to upgrades that were considered.

(b) Set forth actions to resolve any impacts that may result across the seams between the Parties' systems due to such system additions or upgrades; and

(c) Describe results of the analysis for the combined transmission systems, as well as the procedures, methodologies, and business rules that were utilized in preparing and completing the joint transmission analysis.

Coordination of studies required for the development of the Coordinated System Plan will include the following steps:

(a) Every three years, the Parties shall perform a comprehensive, coordinated regional transmission expansion planning study. Sensitivity analyses will be performed, as required, during the off years based on a review by the JPC and IPSAC of discrete reliability problems or operability issues that arise due to changing system conditions. Ad hoc study groups may be formed as needed to address localized seams issues identified.

(b) Each Party will be responsible for providing the technical support required to complete the analysis for the study. The responsibility for the coordinated study and the compilation of the coordinated study report will alternate between the Parties.

(c) The JPC will develop a scope and procedure for the inter-regional planning assessment. The scope of the study will include evaluations of the transmission system against the reliability criteria, operational performance criteria, and economic performance criteria applicable to each Party. Each Party will provide a baseline model that includes all transmission enhancements included in the party's regional transmission expansion plan, and all of the committed interconnection projects and any associated transmission upgrades.

(d) The Parties will use planning models that are developed in accordance with the procedures to be established by the JPC. Exchange of power flow models will be in a format that is acceptable to both Parties and will use a consistent bus numbering convention and bus naming convention to minimize work that is needed to merge detailed power flow models.

(e) The study will initially evaluate the reliability of the combined transmission systems. Any upgrades required to resolve criteria violations will be agreed upon and included in an updated baseline model.

(f) The performance of the combined transmission systems will be tested against agreed upon operational and economic criteria, where applicable, using the updated baseline model. Upgrades required to resolve operational and/or economic performance criteria violations will be included in the Coordinated System Plan.

(g) Economic criteria applicable to either Party will be developed and filed by that Party with input from its stakeholders.

Section 9.4 Allocation of Costs of Upgrades.

Section 9.4.1 Upgrades Associated with Interconnections. Costs associated with transmission system upgrades required as a result of the across-border reliability related impacts of requests for generation interconnection will be recovered under the terms of the tariff of the impacted Party and consistent with applicable federal or provincial regulatory policy.

Section 9.4.2 Upgrades Associated with Transmission Service Requests. Costs associated with transmission system upgrades required as a result of any across-border reliability related impacts of requests for long-term firm delivery service requests will be recovered under the terms of the tariff of the impacted Party and consistent with applicable federal or provincial regulatory policy.

Section 9.4.3 Upgrades Under Coordinated System Plan. Cost responsibility for the transmission upgrades identified in the Coordinated System Plan to resolve thermal or reactive system constraints related to reliability criteria or operational or economic system performance will be assigned to the Parties equitably, based on the nature of the constraint being resolved. The JPC will develop procedures for evaluating, on a case-by-case basis, the relative contribution of the Party's systems to the constraint and the relative benefits derived by the parties by the resolution of the constraint. The JPC will propose an allocation of costs for such transmission system upgrades. The proposed allocation of costs will be reviewed with the

IPSAC and the appropriate multi-state entities. Stakeholder input will be taken into consideration by the JPC in arriving at a consensus allocation of costs. Upgrade proposals and cost allocations are subject to the approval process of both Parties for transmission upgrades. Each Party's allocation and the recovery of the costs of such Network Upgrades shall be consistent with the terms and conditions of its own OATT, as it may be modified from time to time pursuant to the rights of various parties under the Federal Power Act.

Section 9.5 Agreement to Enforce Duties to Construct and Own. To obtain Network Upgrades under this Article IX, SPP will enforce obligations to construct and own or finance enhancements or additions to transmission facilities in accordance with the SPP Membership Agreement and the SPP OATT, as both may be amended or restated from time to time, and MIDWEST ISO will enforce obligations to construct enhancements or additions to transmission facilities in accordance with the Agreement of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, as it may be amended or restated from time to time.

ARTICLE X
JOINT CHECKOUT PROCEDURES

Section 10.1 Scheduling Checkout Protocols.

Section 10.1.1 Scheduling Protocols. The Parties agree that each Party will leverage technology, where feasible, to perform electronic approvals of schedules and to perform electronic checkouts, in lieu of telephone calls. The Parties agree to follow the following scheduling protocols:

Section 10.1.1.1 Each Party, acting as the scheduling agent for their respective Control Areas, will conduct all checkouts with their first tier Control Areas or the scheduling agent acting on behalf of those first-tier Control Areas. A first tier Control Area is any Control Area that is directly connected to any Party's members' Control Area.

Section 10.1.1.2 The Parties will require all schedules, other than reserve sharing or other emergency events and loss payback schedules, to be tagged via the NERC tagging standard. For reserve sharing and other emergency schedules that are not tagged, the Parties will enter manual schedules after the fact into their respective scheduling systems to facilitate checkout between the Parties.

Section 10.1.1.3 When there is a scheduling conflict, the Parties will work in unison to modify the schedule as soon as practical. If there is a scheduling conflict that is identified before the schedule has started, then both Parties will make the correction in real-time and not wait until the quarter hour. If the schedule has already started and one Party identifies an error, then the Parties will make the correction at the earliest quarter hour increment. If a scheduling conflict cannot be resolved between the Parties (but the source and sink have agreed to a MW value), then the Parties will both adjust their numbers to that same MW value. If source and sink are unable to agree to a MW value, then the previously tagged value will stand for both Parties.

Section 10.1.1.4 For Control Areas or associated scheduling agents that do not use the respective Parties' electronic scheduling interfaces, the Parties will contact those entities by telephone to perform checkouts.

Section 10.1.1.5 The Parties will perform the following types of checkouts:

(a) Pre-schedule (Day-Ahead) daily between 1800 and 2200 hours;
- Intra-hour checkout/schedule confirmation will occur as required due to intra-hour scheduled changes.

(b) Hourly Before the Fact (Real-Time);
- Hourly before the fact checkout includes the verification of import and export totals in addition to net scheduled interchange ("NSI") for control areas with that ability. At a future time, the Parties may checkout individual schedules.
- Hourly checkout is performed starting at the half hour and ending at the ramp hour.

(c) After the Fact (Day End) daily starting at 0100 hours; and

(d) After the Fact (Monthly) daily on a month to date basis (usually via email) starting on the first business day of the month and ending by the tenth (10^{th}) business day of that following month.

Section 10.1.1.6 The Parties will require that each of these checkouts be performed with first tier Control Areas. If a checkout discrepancy is discovered, the Parties will use the NERC tag to find where the discrepancy exists. The Parties will require any entity that conducts business within its region to checkout with the Parties using NERC tag numbers; special naming convention used by that entity or other naming conventions given to schedules by other entities will not be permitted.

ARTICLE XI
VOLTAGE CONTRAL AND REACTIVE POWER COORDINATION

11.1 Coordination Objectives. Each Party acknowledges that voltage control and reactive power coordination are essential to promote reliability. Therefore, the Parties establish procedures ("Voltage and Reactive Power Coordination Procedures") under this Article by which they shall conduct such coordination.

11.1.1 The Voltage and Reactive Power Coordination Procedures address the following components: (a) procedures to assist the Parties in maintaining a wide area view of interconnection conditions by enhancing the coordination of voltage and reactive levels throughout their RTO footprints; (b) procedures to ensure the maintenance of sufficient reactive reserves to respond to scenarios of high load periods, loss of critical reactive resources, and unusually high transfers; and (c) procedures for sharing of data with other neighboring Reliability Coordinators for their analysis and coordinated operation.

11.1.2 The Parties will review the Voltage and Reactive Power Coordination Procedures from time to time to make revisions and enhancements as appropriate to accommodate additional capabilities or changes to industry reliability requirements.

Section 11.2 Voltage and Reactive Power Coordination Procedures. The Parties will utilize the following procedures to coordinate the use of voltage control equipment to maintain a reliable bulk power transmission system voltage profile on their respective systems.

11.2.1 Under normal conditions, each Party will coordinate with the owners of the transmission facilities subject to its control and the Control Areas as necessary and feasible to supply its own reactive load and losses at all load levels.

11.2.2 Voltage schedule coordination is the responsibility of each Party. Generally, the voltage schedule is determined based on conditions in the proximity of generating stations and Extra High Voltage ("EHV") (defined as 230 KV facilities and above) stations with voltage regulating capabilities. Each Party works with its respective owners of transmission facilities and Control Areas to determine adequate and reliable voltage schedules considering actual and post-contingency conditions.

11.2.3 Each Party will establish voltage limits at critical locations within its own system and exchange this information with the other Party. This information shall include normal high voltage limits, normal low voltage limits, post-contingency emergency high voltage limits and post-contingency emergency low voltage limits, and, shall identify the voltage limit value (if available) at which load shedding will be implemented.

11.2.4 Each Party will maintain awareness of the voltage limits in the other Party's area (where the EMS Model includes sufficient detail to permit this) and awareness of outages and potential contingencies that could result in violation of those voltage limits.

11.2.5 The Parties will clearly communicate the level of voltage support needed during pre- or post-contingency conditions requiring voltage and reactive power coordination.

11.2.6 Each Party shall maintain a list of actions that are available to be taken when voltage support is necessary to respond to anticipated or prevailing system conditions.

11.2.7 Each calendar quarter the Parties will exchange voltage schedules and shall meet and confer to identify system conditions that could impact the schedules and determine adjustments to the schedules as are consistent with reliability.

11.2.8 In concert with the coordination of Outages addressed in Article VII and the Parties' respective day-ahead reliability analysis processes, the Parties will coordinate the impact of outages and system conditions on the voltage/reactive profile. Coordination will include the following elements:

11.2.8.1 Each Party will review its forecasted loads, transfers, and all information on available generation and transmission reactive power sources at the beginning of each shift.

11.2.8.2 If no reactive problems are anticipated after the review, each Party will operate independently in accordance with the above stated criteria and any individual system guidelines for the supply of the Party's reactive power requirements.

11.2.8.3 If either Party anticipates reactive problems after the review, it may request joint implementation of reactive support levels under these Voltage and Reactive Power Coordination Procedures, as it deems appropriate to the situation. When a Party calls for a particular level of support to be implemented under these procedures, it or the applicable Control Area must identify the time it will start adjusting its system, the support level it is implementing, and the voltage problem area.

11.2.8.4 If a Party experiences an actual low or high voltage condition after initial reactive support measures are taken, then the emergency reactive support level is implemented for the area experiencing the problem. The Party will also notify applicable Reliability Coordinators as soon as feasible. In addition, the Voltage and Reactive Power Coordination Procedures are to be consulted to determine if further action is necessary to correct an undesirable voltage situation.

11.2.9 The Parties will coordinate the use of voltage control equipment to maintain a reliable bulk power transmission system voltage profile on the SPP, MIDWEST ISO, and surrounding systems. The following procedures are intended to ensure that bulk systems voltage levels enhance system reliability.

11.2.9.1 Specific Voltage Schedule Coordination Actions.

(a) Each Party has operational or functional control of reactive sources within its system and will direct adjustments to voltage schedules at appropriate facilities.

(b) Each Party generally will adjust its voltage schedules to best utilize its resources for operation.

(c) If a Party anticipates voltage or reactive problems, it will inform the other Party (operations planning with respect to future day and Reliability Coordinator with respect to same day) of the situation, describe the conditions, and request voltage/reactive support under these Procedures. As a part of the request, the Party must identify the specific area where voltage/reactive support is requested and provide an estimate of the magnitude and time duration of the request as well as the specific voltage and limit.

(d) The requesting Party will arrange a conference call between the affected Control Areas/transmission owners and the Parties. The purpose of this call is to ensure that the situation is fully understood and that an effective operating plan to address the situation has been developed.

(e) Each Party will implement or direct voltage schedule changes requested by the other Party, provided that a Party may decline a requested change if the change would result in equipment violations or reduce the effective operation of its facilities. A Party that declines a requested change must inform the requesting Party that the request cannot be granted and state the reason for denial.

11.2.10 Voltage/Reactive Transfer Limits.

11.2.10.1 Each Party may monitor power transfer on interfaces defined as a Flowgate used to control voltage collapse conditions. In cases where the potential for voltage collapse (or cascading) is identified, prompt voltage support and generation adjustments are needed. Generation adjustment requests to avoid voltage collapse or cascading conditions must be clearly communicated and implemented promptly. Using these limits the Parties will implement the following real-time coordination:

(a) At 95% of Interface Limit

- A Party, which observes the reading shall call the other Party to discuss whether further analysis is required.

- The Party owning the Flowgate will notify other Reliability Coordinators via the reliability coordinator information system (RCIS).
- The Parties will conduct a conference call with the affected Control Areas to discuss reactive outputs and/or capabilities.
- The applicable Party takes appropriate actions, which may include re-dispatching generation and directing schedule curtailments.

(b) Exceeding Interface Limit

- The Party owning the Flowgate will declare an emergency and inform other Reliability Coordinators of the emergency.
- The applicable Party will take immediate action, which may include generation redispatch, ordering immediate schedule curtailments, and, if required, load shedding.

11.2.10.2 Where feasible, and if both Parties' EMS models have sufficient detail, each Party will attempt to duplicate the other Party's power transfer evaluation in order to provide backup limit calculation in the event that the primary Party is unable to accurately determine the appropriate reliability limits.

11.2.10.3 If a new power transfer interface is determined to exist and detailed modeling does not exist for the interface, the Parties will coordinate to determine how their models need to be enhanced and to determine procedures for coordination in furtherance of the enhancement.

ARTICLE XII
ADDITIONAL COORDINATION PROVISIONS

Section 12.1 Application of Congestion Management Process. The Parties have agreed to certain operating protocols under this Agreement to ensure system reliability and efficient market operations as systems exist and are contemplated as of the Effective Date. These protocols include the Congestion Management Process to be developed and applicable NERC reliability plans. As addressed in Section 3.1, the Parties expect that these systems and the operating protocols applicable to these systems will change and revisions of this Agreement will be required from time to time.

Section 12.2 Operating Objectives, Changes. The Parties have agreed to certain operating protocols under this Agreement to ensure system reliability and efficient market operations as systems exist and are contemplated as of the Effective Date. The Parties expect that these systems and the operating protocols applicable to these systems will change upon the startup of Phase 3, Market to Market implementation. The operating objectives of this Agreement can be fulfilled efficiently and economically only if the Parties, from time to time, review and as appropriate revise the requirements stated herein in response to such changes, including deleting, adding, or revising requirements and protocols. Prior to the initiation of Phase 3, the Parties will develop a Phase 3 White Paper containing protocols to achieve the following objectives:

Section 12.3 Additional Provisions Concerning Phase 3, Market to Market.

Section 12.3.1 Calculation Consistency. The Parties' goal will be that the energy prices calculated by both Parties for relevant interfaces between their respective markets are coordinated and consistent. Therefore, to the extent that such prices are not identical, the Parties agree to work in good faith to send the most consistent economic signal possible to all market participants.

Section 12.3.2 Overview of the Market-to-Market Coordination Process. The fundamental philosophy of the Market-to-Market transmission congestion coordination process is to allow any transmission constraints that are significantly impacted by generation dispatch changes in both markets to be jointly managed in the security-constrained economic dispatch models of both Parties. This joint management of transmission constraints near the market borders will provide the most efficient and least costly transmission congestion management and will also provide coordinated pricing at the market boundaries.

This Market-to-Market coordination process should build upon the Parties' Market to Non-market coordination process as a starting point. Before the implementation of Phase 2, the Parties will have agreed upon the inter-regional coordination process between a market region and a non-market region (*i.e*. a market to non-market interface). The set of transmission flowgates in each market that can be significantly impacted by the economic dispatch of generation serving load in the adjacent market will be identified by the Parties. These flowgates will then be monitored to measure the impact of market flows and loop flows from adjacent regions. The procedures developed by the Parties will provide a framework for calculating the resulting powerflow impacts resulting from the market-based economic dispatch in one region on the transmission facilities in an adjacent region and vice versa. In addition, the Parties will have reached agreement on how the market flow impacts will be managed on an interregional basis within the existing NERC IDC to enhance the effectiveness of the NERC interregional congestion management process. Lastly, the Parties agree that flow entitlement for Network and Firm transmission utilization in one region has an impact on the transmission facilities in an adjacent region.

The Market-to-Market coordination process builds on the work already completed as described above because of the continuing requirement to coordinate with adjacent regions even after the Parties' markets are implemented.

Section 12.3.3 Identification of Transmission Constraints that Require Coordinated Transmission Congestion Management. Only a subset of all transmission constraints that exist in either market will require coordinated congestion management. This subset of transmission constraints will be identified in a manner similar to the method described above. The list of transmission constraints will be limited to only those for which at least one generator in the adjacent market has a significant power distribution factor, as agreed upon by the Parties, with respect to serving load in the adjacent region.

Section 12.3.4 Real-time Market Coordination. The Parties will explore joint methods to relieve the other Party's binding constraint(s) in real-time.

Section 12.3.5 Coordination of Interregional Transactions (via Proxy Buses). In order for the Market-to-Market coordination to function properly, the proxy bus models for the Parties must be coordinated to the same level of granularity. The proxy bus modeling approaches should be consistent at the market borders.

Section 12.3.6 Evolution of the Market-to-Market Coordination Process. Nothing in this Agreement will preclude the Parties from further evolving their market coordination process in conjunction with input from their respective market monitors.

Section 12.3.7 Coordinated Emergency Generation Redispatch. The Parties shall follow a security constrained, least-cost dispatch protocol in response to system emergencies, and the costs thereof shall be reflected in, and compensated through, relative energy prices values. However, in the event that costs not cognizable under energy prices are incurred, the Party within which the affected resources are located shall reimburse such resource for direct incremental cost, subject to inter-Party reimbursement in the event that the costs incurred by one Party were caused by a system emergency in the other Party.

Additionally, in the absence of the need to coordinate congestion or address a system emergency, a Party shall be entitled to request that the other Party dispatch a generation unit, subject to the Parties' agreement with respect to compensation for the dispatch.

Section 12.3.8 Joint Reliability Coordination.

Section 12.3.8.1 Introduction. The Parties will explore and develop market procedures to be used in emergency conditions. The procedures shall be used solely when, in the exercise of Good Utility Practice, a Party determines that the redispatch of generation units on the other Party's transmission system would reduce or eliminate the need to resort to Transmission Loading Relief or other transmission-related emergency procedures.

Section 12.3.8.2 Identification of Transmission Constraints.

(a) On a periodic basis determined by the Parties, the Parties shall identify potential transmission operating constraints that could result in the need to use Transmission Loading Relief or other emergency procedures in order to alleviate the transmission constraints, the need for which could be reduced or eliminated by the redispatch of generation on the other's system.

(b) In addition to the identification of such potential transmission operating constraints, the Parties shall each identify generation units on the other Party's system, the redispatch of which would alleviate the identified transmission constraints.

(c) From the identified transmission constraints, the Parties shall agree in writing on the transmission operating constraints and redispatch options that shall be subject to this Section until otherwise agreed. In reaching such agreement, the Parties shall endeavor reasonably to limit the number of transmission constraints that are subject to this Section so as to minimize potential cost shifting among market participants in the control areas of the Parties resulting from the redispatch of generation under this Section. Both Parties shall post the transmission operating constraints that are subject to this Section on their respective Internet sites.

Section 12.3.8.3 Redispatch Procedures. If (i) a transmission constraint subject to this Section 12 occurs and continues or reasonably can be expected to continue after the exhaustion of all economic alternatives that are reasonably available to the transmission system on which the constraint occurs and (ii) the MIDWEST ISO or SPP, as applicable, has determined that it must either use Transmission Loading Relief or other emergency procedures, then (iii) the affected entity may request the other to redispatch one or more of the previously identified generation units to alleviate the transmission constraints. Upon such request, the MIDWEST ISO or SPP, as applicable, shall redispatch such generation if it is then subject to its dispatch control and such redispatch is consistent with good utility practice.

Section 12.3.9 Equitable Compensation for Generation Redispatch. Prior to the implementation of Phase 3, the Parties agree to develop a methodology to compensate a Party that redispatches generation at the request of the other Party in order to relieve a congestion constraint.

ARTICLE XIII
EFFECTIVE DATE

Section 13.1 The Parties agree to file this Agreement jointly with FERC on or before _____ and to cooperate with each other as necessary and appropriate to facilitate such filing. In that filing, the Parties shall request FERC to approve an effective date of _____ ("Effective Date" is the date specified by the FERC).

ARTICLE XIV
COOPERATION AND DISPUTE RESOLUTION PROCEDURES

Section 14.1 Administration of Agreement. The SACC established under the Memorandum of Understanding, shall perform the following with respect to this Agreement:

(a) Meet no less than once annually to determine whether changes to this Agreement would enhance reliability, efficiency, or economy and to address other matters concerning this Agreement as either Party may raise.

(b) Conduct additional meetings upon Notice given by either Party, provided that the Notice specifies the reason for the requested meeting.

(c) Establish task forces and working committees as appropriate to address any issues a Party may raise in furtherance of the objectives of this Agreement.

(d) Conduct dispute resolution in accordance with this Article.

(e) Initiate process reviews at the request of either Party for activities undertaken in the performance of this Agreement.

The SACC shall have the authority to make decisions on issues that arise during the performance of the Agreement based upon consensus of the Parties' representatives thereto.

Section 14.2 Dispute Resolution Procedures. The Parties shall attempt in good faith to achieve consensus with respect to all matters arising under this Agreement and to use reasonable efforts through good faith discussion and negotiation to avoid and resolve disputes that could delay or impede either Party from receiving the benefits of this Agreement. These dispute resolution procedures apply to any dispute that arises from either Party's performance of, or failure to perform, this Agreement and which the Parties are unable to resolve prior to invocation of these procedures.

Section 14.2.1 Step One. In the event a dispute arises, a Party shall give written notice of the dispute to the other Party. Within ten (10) days of such Notice, the SACC shall meet and the Parties will attempt to resolve the Dispute by reasonable efforts through good faith discussion and negotiation. Each Party shall also be permitted to bring no more than two (2) other individuals to Executive Committee meetings as subject matter experts; however, all representatives must be employees of the Party they represent. In addition, if the Parties agree that legal representation would be useful in connection with a meeting, each Party may bring two (2) attorneys (who need not be employees of the Party they represent). In the event the SACC is unable to resolve within twenty (20) days of such Notice, either Party shall be entitled to invoke Step 2.

Section 14.2.2 Step Two. A Party may invoke Step 2 by giving Notice thereof to the SACC. In the event a Party invokes Step 2, the SACC shall, in writing, and no later than five (5) days after the Notice, refer the dispute in writing to the Parties' Presidents for consideration. The Parties' Presidents shall meet in person no later than fourteen (14) days after such referral and shall make a good faith effort to resolve the dispute. The Parties shall serve upon each other, written position papers concerning the dispute, no later than forty-eight (48) hours in advance of such meeting. In the event the Parties' Presidents fail to resolve the dispute, either Party shall be entitled to invoke Step Three.

Section 14.2.3 Step Three. Upon the demand of either Party, the dispute shall be referred to FERC's Office of Dispute Resolution for mediation, and upon a Party's determination at any point in the mediation that mediation has failed to resolve the dispute, either Party may seek formal resolution by initiating a proceeding before FERC.

Section 14.2.4 Exceptions. In the event of disputes involving Confidential Information, infringement or ownership of Intellectual Property or rights pertaining thereto, or any dispute where a Party seeks temporary or preliminary injunctive relief to avoid alleged immediate and irreparable harm, the procedures stated in Section 14.2 and its subparts shall apply but shall not preclude a Party from seeking such temporary or preliminary injunctive relief, provided, that if a Party seeks such judicial relief but fails to obtain it, the Party seeking such relief shall pay the reasonable attorneys' fees and costs of the other Party incurred with respect to opposing such relief.

ARTICLE XV
RELATIONSHIP OF THE PARTIES

Section 15.1 Relationship Between this Agreement and Energy Markets. The Parties agree that execution of this Agreement will further enable the Parties to address many of the specific tasks that are required prior to the creation of a functioning Market by one or both of the Parties. Specifically, Articles III through XII of this Agreement detail certain assignments that may pertain to the reliability and administration of adjacent energy markets. To ensure efficient handling of tasks hereunder the Parties agree to cooperate in good faith to address further protocols that may be required to facilitate each Party's efforts to administer its respective markets.

ARTICLE XVI
ACCOUNTING AND ALLOCATION OF COSTS OF JOINT OPERATIONS

Section 16.1 Revenue Distribution. This Agreement does not modify any prior agreement with either Party's Transmission Owners with regard to revenue distribution. All distribution of revenue received under this agreement shall be distributed by the party receiving such revenue in accordance with the terms of such party's prior agreement with their Transmission Owners.

Section 16.2 Billing and Invoicing Procedures. Each Party shall render invoices to the other Party for amounts due under this Agreement in accordance with its customary billing practices and payment shall be due in accordance with the invoicing Party's customary payment requirements. All payments shall be made in immediately available funds payable to the invoicing Party by wire transfer pursuant to instructions set out by the Parties from time to time. Interest on any amounts not paid when due shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

Section 16.3 Access to Information by the Parties. Each Party grants the other Party, acting through its officers, employees and agents such access to the books and records of the other as is necessary to audit and verify the accuracy of charges between the Parties under this Agreement. Such access shall be at the location of the Party whose books and records are being reviewed pursuant to this Agreement and shall occur during regular business hours.

ARTICLE XVII
RETAINED RIGHTS OF PARTIES

Section 17.1 Parties Entitled to Act Separately. This Agreement does not create or establish, and shall not be construed to create or establish, any partnership or joint venture between the Parties. This Agreement establishes terms and conditions solely of a contractual relationship, between two independent entities, to facilitate the achievement of the joint objectives described in the Agreement. The contractual relationship established hereunder implies no duties or obligations between the Parties except as specified expressly herein. All obligations hereunder shall be subject to and performed in a manner that complies with each Party's internal requirements; provided, however, this sentence shall not limit either Party's payment obligation under Article XVI or indemnity obligation under Section 18.3.1 or Section 18.3.2, respectively.

Section 17.2 Agreement to Jointly Make Required Tariff Changes to Implement Agreement. The Parties agree that they shall cooperate in good faith in the filing of any Section 205 filings before FERC that may be required to implement the terms of this Agreement to facilitate the Effective Date. Whenever practicable, the Parties agree that they shall make simultaneous filings with FERC concerning such Tariff filings.

ARTICLE XVIII
ADDITIONAL PROVISIONS

Section 18.1 Confidentiality.

Section 18.1.1 <u>Meaning</u>. The term “Confidential Information” shall mean: (a) all information, whether furnished before or after the Effective Date, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked “confidential” or “proprietary” or which under all of the circumstances should be treated as confidential or proprietary; (b) all reports, summaries, compilations, analyses, notes or other information of a Party hereto which are based on, contain or reflect any Confidential Information; and (c) any information which, if disclosed by a transmission function employee of a utility regulated by the FERC to a market function employee of the same utility system, other than by public posting, would violate the FERC’s Standards of Conduct set forth in 18 CFR § 37 et seq. and the Parties’ Standards of Conduct on file with the FERC.

Section 18.1.2 <u>Protection</u>. During the course of the Parties’ performance under this Agreement, a Party may receive or become exposed to Confidential Information. Except as set forth herein, the Parties agree to keep in confidence and not to copy, disclose, or distribute any Confidential Information or any part thereof, without the prior written permission of the issuing Party. In addition, each Party shall ensure that its employees, its subcontractors and its subcontractors’ employees and agents to whom Confidential Information is exposed agree to be bound by the terms and conditions contained herein. Each Party shall be liable for any breach of this Section by its employees, its subcontractors and its subcontractors’ employees and agents. This obligation of confidentiality shall not extend to information that, at no fault of the recipient Party, is or was (1) in the public domain or generally available or known to the public; (2) disclosed to a recipient by a third party who had a legal right to do so; (3) independently developed by a Party or known to such Party prior to its disclosure hereunder; and (4) which is required to be disclosed by subpoena, law or other directive or a court, administrative agency or arbitration panel, in which event the recipient hereby agrees to provide the issuing Party with prompt Notice of such request or requirement in order to enable the issuing Party to (a) seek an appropriate protective order or other remedy, (b) consult with the recipient with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. In the event that such protective order or other remedy is not obtained, or that the issuing Party waives compliance with the provisions hereof, the recipient hereby agrees to furnish only that portion of the Confidential Information which the recipient’s counsel advises is legally required and to exercise best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.

Section 18.2 Protection of Intellectual Property.

(a) All Intellectual Property (as defined below), and modifications to, and enhancements of, and derivatives of such Intellectual Property (i) owned by a Party on or before the effective date of this Agreement; or (ii) developed by a Party after the effective date of this Agreement, shall remain the sole property of such Party, and no right, title or interest to such Intellectual Property shall be granted to any other Party.

(b) Except as expressly set forth in a subsequent binding agreement, no Party shall use, convey or disclose the Intellectual Property of another Party without the express written consent of such other Party and nothing herein shall be construed to be a license or other transfer by a Party of any Intellectual Property or interests therein to another Party.

(c) For purposes of this Agreement:

- "Intellectual Property" means all patent rights (including patent applications, disclosures and Inventions (as defined below), rights of priority, mask work rights, copyrights, moral rights, trade secrets, know-how and any other intellectual property rights recognized in any country or jurisdiction of the world including trademarks, trade names, logos, service marks, and other designations of source; and
- "Inventions" means any idea, design, concept, technique, method, discovery or improvement conceived of and actually or constructively can be reduced to practice for which a patent application is or may be filed in the United States or in any foreign country, or for which a patent has issued in the United States or in any foreign country.

Section 18.3 Indemnity.

Section 18.3.1 Indemnity of MIDWEST ISO. SPP will defend, indemnify and hold the MIDWEST ISO harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively "Losses"), brought or obtained by third parties against the Midwest ISO, only to the extent such Losses arise directly from:

(a) gross negligence, recklessness, or willful misconduct of SPP or any of SPP's agents or employees, on the performance of this Agreement, except to the extent the Losses arise from (i) gross negligence, recklessness, willful misconduct or breach of contract or law by the MIDWEST ISO or any of the MIDWEST ISO's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon the MIDWEST ISO or the MIDWEST ISO's agents or employees;

(b) Any claim that the MIDWEST ISO violated any copyright, patent, trademark, license, or other intellectual property right of a third party in the performance of this Agreement;

(c) Any claim arising from the transfer of Intellectual Property in violation of Section 18.2.; and

(d) Any claim that SPP caused physical personal injury due to gross negligence, recklessness, or willful conduct of its agents while on the premises of the MIDWEST ISO.

Section 18.3.2 Indemnity of SPP. The MIDWEST ISO will defend, indemnify and hold SPP harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively "Losses"), brought or obtained by third parties against SPP, only to the extent such Losses arise directly from:

(a) gross negligence or recklessness, or willful misconduct of MIDWEST ISO or any of MIDWEST ISO's agents or employees, in the performance of the Agreement, except to the extent the Losses arise from (i) gross negligence, recklessness, willful misconduct or breach of contract or law by SPP or any of SPP's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon SPP or SPP's agents or employees;

(b) Any claim that SPP violated any copyright, patent, trademark, license, or other intellectual property right of a third party in the performance of this Agreement;

(c) Any claim arising from the transfer of Intellectual Property in violation of Section 18.2.; and

(d) Any claim that the MIDWEST ISO caused physical personal injury due to gross negligence, recklessness, or willful conduct of its agents while on the premises of SPP.

Section 18.3.3 Damages Limitation.

Section 18.3.3.1 Except for amounts agreed to be paid under Article XVI by one Party to the other under this Agreement, no Party shall be liable to the other Party, directly or indirectly, for any damages or losses of any kind sustained due to any failure to perform this Agreement, unless such failure to perform was malicious or reckless.

Section 18.3.3.2 Except for amounts agreed to be paid by one Party to the other under this Agreement, any liability of a Party to the other Party hereunder shall be limited to direct damages as qualified by the following sentence. No lost profits, damages to compensate for lost goodwill, consequential damages, or punitive damages shall be sought or awarded.

Section 18.4 Effective Date and Termination Provision. The term of this Agreement commences upon its acceptance or approval by FERC. The Agreement shall terminate and cease to be effective upon FERC acceptance of the mutual agreement by the Parties to terminate the Agreement or other FERC order terminating the Agreement. Nothing in this Agreement shall prejudice the right of either Party to seek termination of this Agreement under Section 206 of the Federal Power Act, or successor section or statute thereof.

Section 18.5 Survival Provisions. Upon termination or expiration of this Agreement for any reason or in accordance with its terms, the following Articles and Sections shall be deemed to have survived such termination or expiration:

Article II - (Definitions and Rules of Construction)
Article XVI - (Accounting and Allocation of Costs of Joint Operations)
Article XVII- (Retained Rights of the Parties)
Article XVIII- (Additional Provisions), except Section 18.11 (Execution of Counterparts) and Section 18.12 (Amendment)

Section 18.6 No Third-Party Beneficiaries. This Agreement is intended solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on, any third party (other than the Parties' successors and permitted assigns).

Section 18.7 Successors and Assigns. This Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns permitted herein, but shall not be assigned except (a) with the written consent of the non-assigning Party, which consent may be withheld in such Party's absolute discretion; and (b) in the case of a merger, consolidation, sale, or spin-off of substantially all of a Party's assets. In the case of any merger, consolidation, reorganization, sale, or spin-off by a Party, the Party shall assure that the successor or purchaser adopts this Agreement and, the other Party shall be deemed to have consented to such adoption.

Section 18.8 *Force Majeure.* No Party shall be in breach of this Agreement to the extent and during the period such Party's performance is made impracticable by any unanticipated cause or causes beyond such Party's control and without such Party's fault or negligence, which may include, but are not limited to, any act, omission, or circumstance occasioned by or in consequence of any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities. Upon the occurrence of an event considered by a Party to constitute a *force majeure* event, such Party shall use reasonable efforts to endeavor to continue to perform its obligations as far as reasonably practicable and to remedy the event, provided that this Section shall require no Party to settle any strike or labor dispute. A Party claiming a *force majeure* event shall notify the other Party in writing immediately and in no event later forty-eight (48) hours after the occurrence of the *force majeure* event. The foregoing notwithstanding, the occurrence of a cause under this Section shall not excuse a Party from making any payment otherwise required under this Agreement.

Section 18.9 Governing Law. This Agreement shall be interpreted, construed and governed by the applicable federal law and the laws of the state of Delaware without giving effect to its conflict of law principles.

Section 18.10 Notice. Whether expressly so stated or not, all notices, demands, requests and other communications required or permitted by or provided for in this Agreement ("Notice") shall be given in writing to a Party at the address set forth below, or at such other address as a Party shall designate for itself in writing in accordance with this Section, and shall be delivered by hand or reputable overnight courier:

Southwest Power Pool, Inc.
415 North McKinley, #800 Plaza West
Little Rock, AR 72205-3020
Attention: General Counsel

Midwest Independent Transmission System Operator, Inc.
701 City Center Drive
Carmel, Indiana 46032
Attention: General Counsel

Section 18.11 Execution of Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon the Parties hereto, notwithstanding that both Parties may not have executed the same counterpart.

Section 18.12 Amendment. Except as may otherwise be provided herein, neither this Agreement nor any of the terms hereof may be amended unless such amendment is in writing and signed by the Parties and such amendment has been accepted by FERC.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

Southwest Power Pool, Inc.

By: ___________________________
Name:
Title:

Date: __________________________

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

By: ___________________________
Name:
Title:

Date:__________________________

39. Applicability of Non-Rate Terms and Conditions

39.1 Bundled Retail and Grandfathered Load: Notwithstanding Sections 37 and 38 of this Tariff, Each Transmission Owner (which is not otherwise taking Network Integration Transmission Service) is subject to the non-rate terms and conditions of this Tariff for: (1) its bundled retail load not having a choice of power suppliers; (2) its bundled retail load that had the right to choose a different power supplier under a state retail access program or legislation and that was retail load served by the Transmission Owner prior to the retail load receiving the right to choose a different supplier; and (3) its bundled load under Grandfathered Agreements. For purposes of this provision the non-rate terms and conditions are those that would apply to Network Customers except that the provisions requiring SPP to provide Network Integration Transmission Service (Section 28.3) and requiring the Network Customer to pay for such Network Integration Transmission Service (Section 34.1) shall not be included in this definition. ~~for (1) Section 28 other than the provision in Section 28.1 requiring Ancillary Services pursuant to Section 3 and Section 28.2; (2) Section 29 other than Sections 29.3 and 29.4; and (3) Sections 34.1, 34.2 and 34.3.~~ In addition, unless a Transmission Owner executes a Service Agreement under this Part III, it will not be considered as taking Network Integration Transmission Service.

SOUTHWEST POWER POOL

MEMBERSHIP AGREEMENT

2.0 Rights, Powers And Obligations Of SPP

SPP possesses the rights, powers, and obligations as detailed in this Section 2.

2.1 Operation and Planning

2.1.1 General

a. SPP shall schedule transactions and to administer transmission service over Tariff Facilities as necessary to provide service in accordance with the SPP OATT.
b. SPP shall function in accordance with Good Utility Practice and shall conform to applicable reliability criteria, policies, standards, rules, regulations, guidelines and other requirements of SPP and NERC, Transmission Owner's specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements specified in this paragraph), and all applicable requirements of federal and state regulatory authorities.
c. SPP shall maintain a publicly available registry of all facilities that are not classified as critical energy infrastructure information that constitute the Electric Transmission System.
d. SPP shall review and approve, as appropriate, requests for service, schedule transmission transactions, and determine available transfer capability under the OATT, provided that SPP shall coordinate with the Transmission Owner when processing requests for service involving its Tariff Facilities.
e. SPP shall be responsible for coordinating with neighboring regional organizations and/or non-member transmission owners or providers as appropriate.
f. SPP shall not exercise its administration of transmission service over the Tariff Facilities in such a way as to interfere with contracts between Transmission Owner and any Transmission Customer that are in effect as of the Effective Date of this Agreement except as permitted by the OATT.
g. SPP shall be responsible for documenting all transmission service requests, the disposition of such requests, and any supporting data required to support the decision with respect to such requests. SPP shall negotiate as appropriate to develop reciprocal service, equitable tariff application, compensation principles, and any related arrangements.

h. SPP shall propose and file with FERC pursuant to Section 205 of the Federal Power Act modifications to the OATT and make any other necessary filings subject to approval by the Board of Directors.

i. SPP shall develop penalties and incentives, subject to FERC filings where appropriate.

j. SPP shall direct Transmission Owner pursuant to the provisions of Section 3.3 to construct transmission facilities in accordance with coordinated planning criteria, or if necessary under the OATT.

k. SPP shall have the authority to direct the day-to-day operations of the Tariff Facilities in order to carry out its responsibilities as a Transmission Provider and Reliability Coordinator as described in SPP's Operational Authority Reference Document; provided, however, nothing in this Agreement or the OATT shall be construed to require a change in the physical control of any Tariff Facilities using a Party's existing facilities or equipment.

l. SPP shall take any actions necessary for it to carry out its duties and responsibilities, subject to receiving any necessary regulatory approvals and any necessary approvals from the Board of Directors.

INDEPENDENT MARKET MONITORING (IMM) SERVICES AGREEMENT

This IMM Services Agreement ("Agreement") is made by and between Southwest Power Pool, Inc. ("SPP"), an Arkansas corporation, and Boston Pacific Company, Inc. (the "IMM"), a District of Columbia corporation. (SPP and the IMM shall be referred to individually herein as a "Party" and collectively as the "Parties.")

1. Engagement of Services. SPP hereby retains the IMM to perform the individual tasks ("Tasks") identified in Exhibit A attached hereto. The aggregation of all Tasks shall be identified herein as the "Services." The Services may be modified from time to time upon mutual agreement of the Parties. If such modifications necessitate an increase or decrease in either (a) the amount due or (b) the time required for performance, such matters shall be agreed upon in writing prior to proceeding with the change. No payment shall be made by SPP for any modification not so directed or authorized prior to proceeding with the modification.

2. Compensation. SPP shall pay the IMM for the Services on (a) a fixed price or (b) a time and materials basis as identified in Exhibit B attached hereto. SPP shall also pay the IMM's reasonable expenses in accordance with the procedures identified in Exhibit B. SPP reserves the right to audit and to examine any cost, payment, settlement or supporting documentation resulting from the provision of any Services. Any such audit(s) shall be undertaken by SPP or its representative from a certified public accounting firm at reasonable times and in conformance with generally accepted auditing standards. The IMM agrees to fully cooperate with any such audit(s).

3. Monthly Charges. The total monthly charges for Services and expenses shall be referred to herein as the Monthly Charges. The IMM shall submit an invoice on a monthly basis for the Monthly Charges and SPP shall pay the IMM as described in Exhibit B for all undisputed amounts, provided that the IMM provides documents with reasonable receipts or other documentation of expenses as SPP might request, including copies of time records. If SPP disputes any amount of the Monthly Charges, then SPP shall identify in writing the reason for challenging such portion of the Monthly Charges, and the Parties shall attempt to resolve such dispute.

4. Limitation on Monthly Charges. Limitations on Monthly Charges are described in Exhibit B.

5. Independent Contractor Relationship. The IMM's relationship with SPP is that of an independent contractor, and nothing in this Agreement is intended to, or should be construed to, create a partnership, agency, joint venture or employment relationship. The IMM retains sole and absolute discretion, control and judgment in the manner and means of carrying out the Services, except as to the policies and procedures set forth herein. The IMM shall not be entitled to any of the benefits which SPP may make available to its employees, including, but not limited to, group health or life insurance, profit sharing or

retirement benefits. The IMM is not authorized to make any representation, contract or commitment on behalf of SPP unless specifically requested or authorized in writing to do so by SPP. The IMM is solely responsible for, and shall file, on a timely basis, all tax returns and payments required to be filed with, or made to, any federal, state or local tax authority with respect to the performance of services and receipt of fees under this Agreement. The IMM is solely responsible for, and must maintain adequate records of, expenses incurred in the course of performing services under this Agreement. No part of the IMM's compensation shall be subject to withholding by SPP for the payment of any social security, federal, state or any other employee payroll taxes. SPP shall have no responsibility for any of the IMM's debts, liabilities or other obligations, or for the intentional, reckless or negligent acts or omissions of the IMM or IMM's employees or agents.

6. Ownership of Intellectual Property.

6.1 Any idea, invention, work of authorship, drawing, design, formula, algorithm, utility, tool, pattern, compilation, program, device, method, technique, process, improvement, development or discovery (hereinafter, collectively, "Inventions"), whether or not patentable, or copyrightable, or entitled to legal protection as a trade secret or otherwise, that the IMM may conceive, make, develop, create, reduce to practice, in the course of performing work under this Agreement shall be owned by the IMM. The IMM hereby grants to SPP an irrevocable, assignable, nonexclusive royalty-free unrestricted license to use, copy, distribute and make derivatives of any proprietary rights or specialized knowledge of the IMM that are part of any work product furnished by the IMM to SPP under this Agreement for SPP's and its affiliates', members', and regulators' internal use.

6.2 All documents, including but not limited to, drawings, specifications, and computer software prepared by the IMM pursuant to this Agreement are instruments of service in respect to the Services. They are not intended or represented to be suitable for reuse by SPP or others on extensions of the Services or on any other project. Any reuse without prior written verification or adaptation by the IMM for the specific purpose intended will be at SPP's sole risk and without liability or legal exposure to the IMM. SPP shall defend, indemnify, and hold harmless the IMM against all claims, losses, damages, injuries, and expenses, including attorneys' fees arising out of or resulting from such reuse. Any verification or adaptation of documents will entitle the IMM to additional compensation at rates to be agreed upon by SPP and the IMM.

7. Intellectual Property Rights. The IMM expressly warrants that there has been no violation, misappropriation or infringement of any trade secret, patent, trademark, copyright, or other third party property right (including without limitation, any violation of a third party license) in any way connected with or arising out of performing the work specified in this Agreement.

8. Confidential Information. The IMM agrees to hold SPP's Confidential Information in strict confidence and not to disclose such Confidential Information to any third parties, except as required for the performance of the Services. "Confidential Information" as used in this Agreement shall mean any and all information related to the current, future and proposed products and services of SPP, its affiliates, suppliers and customers, and includes, without limitation, information concerning research, experimental work, development, engineering, financial information, procurement requirements, purchasing manufacturing, customer lists, business forecasts, sales and merchandising and marketing plans and information. "Confidential Information" also includes proprietary or confidential information of any third party (including all SPP market participants) who may disclose such information to SPP or the IMM in the course of SPP's business. The above obligations shall not apply to Confidential Information which is already known to the IMM at the time it is disclosed, or which before being divulged either (i) has become publicly known through no wrongful act of the IMM; (ii) has been rightfully received from a third party without restriction on disclosure and without breach of this Agreement; (iii) has been independently developed by the IMM; (iv) has been approved for release by written authorization of SPP; or (v) has been disclosed pursuant to a requirement of a government agency or of law. Upon termination of this Agreement by either party for any reason, the IMM agrees to promptly deliver to SPP the original and any copies of the Confidential Information. The IMM agrees to certify in writing that the IMM has so returned all such Confidential Information.

9. Conflicts of Interest. The IMM warrants that there is no conflict of interest (as defined in the terms of Exhibit C) between the IMM's other agreements, if any, and the activities to be performed hereunder. The IMM shall advise SPP if a potential conflict of interest arises, as required by Exhibit C.

10. Insurance. Before commencing the work, the IMM shall procure and maintain at its own expense the following minimum insurance in forms and with insurance companies acceptable to SPP:

10.1 Workers' Compensation insurance for statutory obligations imposed by Workers Compensation, Occupational Disease, or other similar laws, including, where applicable, the United States Longshore and Harbor Workers' Act, the Federal Employees Act, and the Jones Act. Employers' liability insurance shall be provided with a minimum umbrella limit of $1,000,000 per occurrence.

10.2 Business automobile liability insurance with the following minimum limit of liability:

$1,000,000 combined single limit per occurrence.

This insurance is to apply to all owned, non-owned, hired, and leased vehicles used by the IMM in the performance of the work.

10.3 Business general liability insurance including contractual liability insurance covering all operations required to complete the project with the following minimum limit of liability:

$1,000,000 combined single limit per occurrence.

The contractual liability insurance coverage shall insure the performance of the contractual obligations assumed by the IMM under this Agreement.

The commercial general liability insurance coverage shall name SPP as an additional insured and shall include a cross liability clause.

10.4 Professional liability (errors & omissions) insurance, where applicable, covering the professional services being delivered by the IMM with the following minimum limit of liability:

$1,000,000 per wrongful act.

11. Key Personnel. Provisions governing key personnel are described in Exhibit D. Boston Pacific Company, Inc. will enter into subcontracting agreements consistent with this IMM Services Agreement with Appian Corp. and Ross Baldick, Ph.D.

12. Termination. SPP may initiate termination of this Agreement, with or without cause, at any time upon thirty (30) days prior written notice to the IMM. Any termination of this Agreement by SPP is subject to approval by the Federal Energy Regulatory Commission (FERC). The IMM may terminate this Agreement, with or without cause, at any time upon sixty (60) days prior written notice to SPP. Upon termination of this Agreement, SPP shall pay the IMM's wind down costs, and the IMM shall use best efforts to minimize all additional charges to SPP as needed to wind down the Services.

13. Noninterference with Business. For a period of two years immediately following the conclusion of the IMM's work hereunder, the IMM agrees not to solicit or induce any employee or independent contractor of SPP to terminate or breach an employment, contractual or other relationship with SPP. SPP agrees to the same terms regarding employees of and subcontractors to the IMM.

14. Survival. The rights and obligations contained in Sections 2 ("Compensation"), 6 ("Ownership of Intellectual Property"), 7 ("Intellectual Property Rights"), 8 ("Confidential Information"), and 13 ("Noninterference with Business") shall survive any termination or expiration of this Agreement.

15. Successors and Assigns. The IMM may not subcontract or otherwise delegate its obligations under this Agreement, without SPP's prior written consent, and it is acknowledged that such approval is contained herein for the IMM's named

subcontractors in Exhibit D. Subject to the foregoing, this Agreement shall be for the benefit of SPP's successors and assigns, and shall be binding on the IMM's assignees.

16. Notices. Any notice required or permitted by this Agreement shall be in writing and shall be delivered as follows with notice deemed given as indicated: (i) by personal delivery when delivered personally; (ii) by overnight courier upon written verification of receipt; (iii) by telecopy or facsimile transmission upon acknowledgment of receipt of electronic transmission; or (iv) by certified or registered mail, return receipt requested, upon verification of receipt. Notice shall be sent to as set forth below or such other address as either party may specify in writing.

If to SPP:

Southwest Power Pool
415 North McKinley
800 Plaza West
Little Rock, AR 72205
Attn: Mr. Richard Dillon
Phone: (501) 614-3200
Fax: (501) 664-9553
Email: rdillon@spp.org

If to the IMM:

Boston Pacific Company, Inc.
1100 New York Avenue, NW
Suite 490 East
Washington, DC 20005
Attn: Mr. Robert Janssen
Phone: (202) 296-5520
Fax: (202) 296-5531
Email: rjanssen@bostonpacific.com

17. Governing Law. This Agreement shall be governed in all respects by the laws of the United States of America and by the laws of the District of Columbia.

18. Severability. Should any provisions of this Agreement be held by a court of law to be illegal, invalid or unenforceable, the legality, validity and enforceability of the remaining provisions of this Agreement shall not be affected or impaired thereby.

19. Waiver. The waiver by SPP of a breach of any provision of this Agreement by the IMM shall not operate or be construed as a waiver of any other or subsequent breach by the IMM.

20. Injunctive Relief for Breach. The IMM's obligations under this Agreement are of a unique character that gives them particular value; breach of any of such obligations shall result in irreparable and continuing damage to SPP for which there shall be no adequate remedy at law; and, in the event of such breach, SPP shall be entitled to injunctive relief and/or a decree for specific performance, and such other and further relief as may be proper (including monetary damages if appropriate).

21. Disputes. In the event of any litigation to enforce or interpret any terms or conditions of this Agreement, the parties agree that such action will be brought in the Superior Court of the District of Columbia (or, if the federal courts have exclusive jurisdiction over the subject matter of the dispute, in the U.S. District Court for the District of Columbia), and the parties hereby submit to the exclusive jurisdiction of said court. In any action in litigation to enforce or interpret any of the terms or conditions of this Agreement, the prevailing party shall be entitled to recover from the unsuccessful party all costs, expenses (including expert testimony) and reasonable attorneys' fees incurred therein by the prevailing party. In no event shall the litigation of any controversy or the settlement thereof delay the performance of this Agreement.

22. Entire Agreement. This Agreement constitutes the entire agreement between the parties relating to this subject matter and supersedes all prior or contemporaneous oral or written agreements concerning such subject matter. The terms of this Agreement shall govern the Services undertaken by the IMM for SPP. While this Agreement presently constitutes the entire relationship between the parties, the provisions of any subsequent market monitoring plan that obtains FERC approval are to be given deference in the case of a conflict with this Agreement. This Agreement may only be changed by mutual agreement of authorized representatives of the parties in writing. Licensing, Intellectual Property Rights and Ownership, and other issues specific to the hardware and software to be produced under a supplemental scope of work will be addressed at the time of such supplemental scope of work.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the date first written above.

Southwest Power Pool, Inc.	Boston Pacific Company, Inc.
By: ______________________	By: Craig R. Roach
Name: ______________________	Name: Craig R. Roach
Title: ______________________	Title: President
Date: ______________________	Date: July 19, 2004

EXHIBIT A
STATEMENT OF WORK

On April 27, 2004, the Board of Directors (the "Board") of Southwest Power Pool, Inc. (SPP) approved the selection of Boston Pacific Company, Inc. and its subcontractors (the "Boston Pacific Team") [1] as its Independent Market Monitor (IMM) based upon the recommendation of the IMM Selection Task Force, which the Board itself chartered. The Selection Task Force chose the Boston Pacific Team through a competitive RFP process in which initial proposals were submitted, a short list was chosen, presentations were made to the Selection Committee by the short-listed bidders, and then a final recommendation was made to the Board.

The Boston Pacific Team will meet all the requirements for an IMM that are prescribed by Federal Energy Regulatory Commission (FERC) in rulings ranging from Order 2000 to the February 2004 Order conditionally granting RTO status to SPP. A brief summary of those requirements, prepared by the Boston Pacific Team as part of its original proposal, can be found in Attachment A-One. In the first year of its work – generally covering the period from Summer 2004 through Spring 2005 – the six primary goals of the SPP IMM are clear: (a) file and win approval from FERC for a market monitoring plan in Fall 2004; (b) design, test, and implement the software and hardware systems needed to execute the market monitoring plan in time for SPP's market start up in Spring 2005; (c) in the context of the market monitoring plan approved by FERC, actually monitor the transmission and energy markets; (d) review and provide advice to SPP on market design; (e) deliver the first IMM Annual Report for SPP in Spring 2005; and (f) provide other services as requested by SPP.

Note that the scope and budget for item (b) will be covered under a supplemental scope of work because it is best to wait until progress has been made on the market monitoring plan before starting work on software and hardware design. For item (c), the focus will be on transmission market monitoring for this first year because the energy market is not yet in place.

The IMM reports directly to the Board. The IMM will work closely with the SPP Market Working Group (MWG) and the SPP Market Monitoring Unit (MMU), and will maintain a strong working relationship with FERC. As directed by the Board, the IMM will build and maintain working relationships with the States.

The titles of tasks in the remainder of this Statement of Work are generally keyed to those in SPP's original solicitation for the IMM.

To assure independence, the Boston Pacific team will not be permitted to provide consulting services to SPP outside of those detailed in this Agreement.

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[1] The subcontractors to Boston Pacific Company, Inc., are Appian Corp. and Professor Ross Baldick of the University of Texas.

1.0 SCOPE OF WORK

1.1 Consulting on Market Design Issues

Task 1.1.1 Development of Market Monitoring Plan

The Boston Pacific Team shall work with SPP to develop a market monitoring plan responsive to SPP's needs and to the FERC's February 2004 order in *Southwest Power Pool* 106 FERC ¶ 61,110 (SPP FERC Order). The market monitoring plan shall involve a review of the SPP market design and, consistent with that design, the development of market monitoring and market power mitigation protocols, accompanying software that implements these protocols, and if required, additional protocols to comply with the Federal Energy Regulatory Commission's November 2003 order in *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations* 105 FERC ¶61,218.

Task 1.1.2 Consulting on Phase I Market Design Activities

Beyond the effort in Task 1.1.1, the Boston Pacific Team shall evaluate the SPP market design and assist with design and testing to ensure the successful start of the Phase I Market by Spring 2005.

Task 1.1.3 Implementation of Software Related to Market Monitoring and Market Power Mitigation Systems

It is best to wait for progress on Task 1.1.1 before defining a scope for software and hardware development. For that reason, a supplemental Statement of Work will be provided later.

However, to start toward that supplement, the Boston Pacific Team (a) will travel to SPP to hear the SPP Staff's presentation on the status of software and hardware development for the energy market expected to begin operation in Spring 2005; (b) provide feedback to SPP Staff; and then (c) prepare a supplemental statement of work which details the next steps toward software and hardware development to implement the market monitoring plan. Work prior to the approval of the supplemental statement of work shall be on time and materials basis, not to exceed $[redacted].

Task 1.1.4 Market Design and Market Power Mitigation Education

The Boston Pacific Team shall educate, as requested, market participants, regulators, and other stakeholders on market design and market power mitigation.

Task 1.1.5 Identification of Weaknesses in Market Design

After market start up in Spring 2005, the Boston Pacific Team, as an ongoing effort, shall identify weaknesses in market design, work with SPP and the SPP MWG on approaches to remedy these weaknesses, and report to the SPP Board of Directors on the outcome of these approaches.

Task 1.1.6 Consulting on Phase 2 and Phase 3 Activities

When requested by the Board, the Boston Pacific Team shall provide an independent opinion on the benefit/cost study performed, per the SPP FERC Order, on the market-based congestion management and ancillary services (Phase 2 and Phase 3 respectively) of the SPP facilitated markets.

1.2 Producing Periodic Market Monitoring Reports

The Boston Pacific Team shall complete all market monitoring reports required by FERC. These consist of the *Annual State of the Market Report*, quarterly and annual metrics reports to facilitate inter-ISO/RTO comparisons, and a quarterly report on indications of market power.

Task 1.2.1 Annual State of the Market Report

The Boston Pacific Team shall produce an *Annual State of the Market Report* to assess the performance of the markets administered by SPP. The Boston Pacific Team's first state of the markets report (Spring 2005), shall, among other things, assess the SPP-administered transmission market and energy market structure, examine spot market energy prices in various trading hubs in and around SPP, and report on progress in inter-ISO/RTO coordination efforts.

Task 1.2.2 Quarterly and Annual Metrics Report

After the Phase 1 Market begins operations in Spring 2005, the Boston Pacific Team shall produce quarterly and annual metrics reports to provide a standardized basis to compare the performance of SPP's market structure and market power mitigation with that of other ISOs/RTOs. In performing this task, the Boston Pacific Team shall work with SPP staff and other SPP organizations, as well as FERC, in the development of metrics to permit inter-ISO/RTO comparisons.

Task 1.2.3 Quarterly Report on Indications of Market Power

After the Phase 1 Market begins operations in Spring 2005, the Boston Pacific Team shall produce a quarterly report on indications of market power to keep SPP and regulators apprised on the potential for and exercise of market power, and make recommendations on how to remove the potential for and ability to exercise market power.

1.3 Conducting Investigations as Requested

The Boston Pacific Team shall closely collaborate on investigations with SPP. This may involve participating in the investigation itself, communicating the progress and resolution of the issue to the party(s) that initiated the investigation, and, if appropriate, recommending changes to the Board of Directors, FERC, and state regulators.

1.4 Maintaining Reporting and Operational Relationships

The Boston Pacific Team shall maintain reporting and operational relationships, including but not limited to those with the SPP Board of Directors, the SPP MMU, the SPP MWG, FERC, state regulators and market participants.

Task 1.4.1 Reporting Relationships

The Boston Pacific Team shall be responsible to the SPP Board of Directors. The Boston Pacific Team shall interact with the SPP MMU, SPP MWG, FERC, and state regulators in the acquisition of data and implementation of the market monitoring function.

Task 1.4.2 Operational Relationships

The Boston Pacific Team may interact with market participants during the development of market design and market mitigation protocols and during ongoing operations. The Boston Pacific Team may obtain data for analysis and review from the MMU and develop market power mitigation tests in concert with the MMU and MWG. The Boston Pacific Team shall also respond to *ad hoc* requests of the SPP Board of Directors.

EXHIBIT B
COMPENSATION

2.0 TIME PERIOD COVERED BY STATEMENT OF WORK

The time period covered by this Statement of Work will start in July 2004, at the date of contract signature, and continue through June 30, 2005.

3.0 COMPENSATION AND PAYMENT

SPP shall compensate the Boston Pacific Team for an amount not to exceed $[redacted] for non-Time & Material tasks (these include 1.1.1, 1.1.4, 1.2.1, and 1.4) as set forth in Section 1.0 Scope of Work and as summarized below. Time and Material tasks could add significantly to the budget and, for large tasks (more than $[redacted]), supplemental scopes of work will be provided as requested by the Board before the Boston Pacific Team begins its work.

SCOPE OF WORK	BUDGET
Consulting on Market Design Issues	[redacted]
Task 1.1.1	
Task 1.1.2	
Task 1.1.3*	
Task 1.1.4**	
Task 1.1.5	
Task 1.1.6	
Producing Periodic Monitoring Reports Task 1.2.1 ***	
Conducting Investigations as Requested Task 1.3	
Maintaining Reporting and Operational Relationships Task 1.4	
TOTAL******	

[redacted]

3.1 Basis of Compensation for Services and Time & Material Tasks

Compensation for services rendered including those for Time & Material tasks shall be based on prices as set forth below for the time period covered by this statement of work:

THE BOSTON PACIFIC TEAM	RATE ($/HR)
Engagement Director	[redacted]
Engagement Manager	[redacted]
Project Manager	[redacted]
Senior Consultant	[redacted]
Research Assistant	[redacted]
Administrative Assistant	[redacted]
Software Adviser (Appian Corp.)	[redacted]
Transmission Adviser (Ross Baldick, Ph.D.)	[redacted]

3.2 Reimbursement of Direct Expenses

SPP shall reimburse the Boston Pacific Team for direct expenses (relating to tasks 1.1.1, 1.1.4, 1.2.1, and 1.4) such as travel and communication for a total amount not to exceed [redacted]% of the total budget of $[redacted], which excludes Time & Material tasks. A supplemental scope and budget will be submitted for Task 1.1.3, including expenses related to the Task.

Direct expenses such as travel and communication relating to tasks 1.1.2, 1.1.5, 1.1.6, 1.2.2, 1.2.3, and 1.3 will be billed at cost as incurred.

3.3 Project Billing Period

The Boston Pacific Team shall prepare monthly invoices for work performed in the prior month based on the prices set forth in 3.1. Invoices unpaid for 90 days will include a [redacted]% per month interest charge for all time after 30 days. If the Boston Pacific Team is performing tasks considered as Time & Materials, then the Boston Pacific Team shall notify SPP of this status prior to performing those tasks.

3.4 Project Billing Controls

The Boston Pacific Team shall establish project billing codes for each task set forth in this Statement of Work such that costs per task can be tracked.

3.5 Expanded SPP Membership

The budget caps herein presume the current SPP membership. If the SPP membership expands, and/or the types of membership change, the budget caps will be increased in a manner to be negotiated.

EXHIBIT C
CONFLICTS OF INTEREST

4.0 CONFLICTS OF INTEREST

4.1 Prohibited Engagements

The Boston Pacific Team shall not advise any client on SPP matters including, but not limited to, SPP's market(s), transmission system, or market rules, and shall not be engaged by any client in any litigation, open regulatory docket, alternative dispute resolution procedure, or arbitration with SPP.

The Boston Pacific Team will not appear for or against a SPP Member before a state regulatory commission within the SPP footprint in any new engagement in the electricity business (after the date of signature) except as required by its role as the SPP IMM or as requested by the state regulatory commission. [The term "footprint" refers to the area covered by the transmission system for which SPP is the transmission provider.]

The Boston Pacific Team will not appear for or against a SPP Member before the Federal Energy Regulatory Commission (FERC) on any matter within the SPP footprint in any new engagement in the electricity business (after the date of signature) except as required by its role as the SPP IMM or as requested by FERC.

4.2 Engagements to Clear

The Boston Pacific Team shall clear other engagements with the SPP Board of Directors or its delegate, before such engagements are accepted, when such an engagement involves the electricity business and is within the boundaries of the transmission system for which SPP is the transmission provider (the SPP footprint).

4.3 Non-Prohibited Engagements

The Boston Pacific Team shall not be prohibited from entering into engagements with (a) SPP Members when the engagement involves the electricity business outside the SPP footprint, and does not directly impact SPP's business and (b) entities that are not SPP Members. Such engagements shall not involve topics prohibited in section 4.1.

4.4 No Direct Financial Interests

Persons of the Boston Pacific Team assisting in this Statement of Work shall not have a direct equity or other financial interest in a SPP Member(s) or affiliate of a SPP Member that is involved in the electricity business. (The term "direct" is meant to exclude investments such as mutual funds in which a person has no direct control.)

4.5 Code of Ethics

All employees of Boston Pacific Company, Inc. and its subcontractors (retained for the purpose of fulfilling this agreement) will sign the attached Code of Ethics. (Please see Attachment C-One)

EXHIBIT D
STAFFING RESPONSIBILITIES AND REQUIREMENTS

5.0 STAFFING RESPONSIBILITIES AND REQUIREMENTS

5.1 The Boston Pacific Team Principals

The Boston Pacific Team shall be principally located at the offices of Boston Pacific Company, Inc. Ross Baldick, Ph.D., shall act as the Independent Transmission Advisor on Systems and Modeling and Appian Corp. shall act as the Independent Database and Software Advisor to the Boston Pacific Team.

The Engagement Director for this Statement of Work shall be Craig Roach, Ph.D., of Boston Pacific Company, Inc. The Engagement Managers shall be Rob Janssen and Jim Sullivan from Boston Pacific Company, Inc., and the lead liaison for Appian Corp. shall be Rick Fasani.

5.2 The Boston Pacific Team Project Management

The Boston Pacific Team shall manage the tasks associated with the Statement of Work to ensure that (a) the work meets SPP's needs and are of professional quality and (b) budget and scheduling timelines are met.

5*.2.1 Project Management Responsibilities and Resources*

The overall responsibility for providing project management shall lie with the Boston Pacific Team Engagement Director, Craig Roach., Ph.D. The Boston Pacific Team Engagement Managers (Rob Janssen and Jim Sullivan) shall be responsible for establishing internal project controls and will work with Rick Fasani from Appian Corp. on the development and implementation of the market monitoring and market power mitigation systems requirements.

5.2.2 Responsibility for Assigning Personnel

The Boston Pacific Team Engagement Manager(s) shall be responsible for assigning the appropriate personnel to perform tasks in connection with this Statement of Work, and ensuring that those tasks meet budget and scheduling requirements. For Task 1.1.3, the Boston Pacific Team shall provide an Engagement Manager (Rick Fasani) and development and testing staff from Appian Corp. to support the implementation of software related to market monitoring and market power mitigation systems by the start of the Phase 1 Market by Spring 2005.

A layout of the proposed Boston Pacific Team Structure is appended as Attachment A-Two to this Statement of Work. The Boston Pacific Team Engagement

Director and/or Engagement Manager(s) shall periodically review and adjust the personnel as needed to improve the efficiency of project controls.

5.2.3 Responsibility for Establishing Milestones

The Boston Pacific Team Engagement Managers shall be responsible for establishing internal project milestones to ensure all tasks are completed on time or ahead of a mutually agreed upon schedule.

5.2.3.A Estimated Initial Timelines

The following below shall serve as estimated initial timelines for non-Time & Materials tasks assuming a start date of late June 2004:

Estimated Initial Timeline for Tasks 1.1.1, 1.1.4, and 1.4

Date	**Activity**
July/August 2004	Meet with Board of Directors, MMU, MWG, FERC Staff, and State representatives to introduce ourselves and to gain insight on expectations for the IMM role in general and market power mitigation protocols in particular
July/ August 2004	Present to the MWG and MMU an initial concept of the market monitoring plan with alternative approaches for market power mitigation
September 2004	Propose and gain feedback on a specific market monitoring and market power mitigation plan and protocols from SPP MWG and MMU and brief SPP Board of Directors
October 2004	Present a draft filing to SPP MWG and MMU and brief SPP Board of Directors
November 2004	Preview the approach with FERC Staff
Early November 2004	Brief market participants as well as State regulators on market monitoring and market power mitigation plan
December 2004	File the plan and protocols with FERC
January 2005	Meet with FERC Staff to gain feedback, respond to questions, and gain insight on the steps necessary to gain approval quickly

Estimated Initial Timeline for Task 1.2.1, 1.2.2, and 1.2.3*

Date	Activity
July/ August 2004	Initiate discussions with SPP MMU and MWG on collection of baseline SPP data needed for *Annual State of the Market Report* and on the form and content of report
July-October 2004	Assess historic and current data concerning non-discriminatory access to transmission in SPP, effectiveness of wholesale spot markets, and other issues on an ongoing basis
November/ December 2004	Brief SPP MMU and MWG on the preliminary findings and present key points outline of *Annual State of the Market Report*
Spring 2005	Present draft *Annual State of the Market Report* to SPP MWG and MMU
Spring 2005	Issue first *Annual State of the Market Report*

* The Boston Pacific Team does not expect to issue Quarterly and Annual Metrics Report (1.2.2) or Quarterly Reports on Indications of Market Power (1.2.3) until after Phase I begins operations. However, the Boston Pacific Team shall initiate discussions with SPP MMU and MWG on suggestions for content and format for these reports.

5.3 SPP Principals and Roles

SPP staff is expected to provide personnel to support Boston Pacific Team's efforts in discharging the tasks set forth in this Statement of Work. The specific amount of resources that SPP shall provide in connection with this Statement of Work will be negotiated between SPP and the Boston Pacific Team.

The three primary tasks that require SPP resources are tasks 1.1.1, 1.1.3, and 1.2.1. For Task 1.1.1, the main efforts are for SPP to (a) respond to the Boston Pacific Team proposals for the market monitoring and market power mitigation plan and (b) review and edit the draft FERC filing detailing the plan before November 2004. For Task 1.1.3, the key effort by SPP is to work with the Boston Pacific Team to ensure that the market monitoring and market power mitigation systems are compatible with SPP's systems and comply with SPP security standards. For Task 1.2.1, the key effort by SPP is to (a) assist the Boston Pacific Team in the collection of baseline SPP data on transmission access and market prices and conditions and (b) review and edit drafts of the first *Annual State of the Market Report*.

ATTACHMENT A-ONE

FERC REQUIREMENTS THAT AFFECT THE ROLE OF SPP's IMM

FERC has frequently defined guidelines for the role of the IMM. The purpose of this section is to summarize our understanding of FERC's requirements. In all of our work, and most notably in the Fall 2004 filing, the Boston Pacific Team will work with SPP to ensure that these requirements are met.

In Order No. 2000, FERC established four minimum characteristics and eight minimum functions that an entity applying for Regional Transmission Organization (RTO) status would have to satisfy; market monitoring is the sixth minimum function. In that order, FERC declined to "prescribe a particular market monitoring plan or the specific elements of such a plan," recognizing that dissimilar markets are likely to have dissimilar monitoring plans.[2]

However, FERC did state that the monitoring plan must include certain standards.[3] For example, the monitoring plan should: (1) be designed such that there is objective information about the markets that the RTO operates or administers and a process by which to propose action regarding issues (e.g., market design flaws, efficiency improvement, market power) identified by that information; (2) assess the behavior of market participants (e.g., whether a participant is affecting the RTO's ability to provide reliable and non-discriminatory service); (3) assess the behavior of other markets that impact the performance of the RTO's operations; (4) identify the markets that will be monitored, and with respect to those markets, assess the structure of the market, market power, and compliance with market rules; (5) establish how information is reported and used; (6) explain any "proposed sanctions or penalties and the specific conduct to which they would be applied;" and (7) "provide an objective basis to observe markets and, if appropriate, provide reports and/or market analyses."[4]

In October 2003, SPP filed for approval as an RTO. The substance of SPP's market monitoring plan as presented in Section 3.17 of the ByLaws and Attachment X in its revised Open Access Transmission Tariff is very responsive to the framework outlined in FERC Order No. 2000. Furthermore, SPP noted that as its markets develop, it intends to update its monitoring plan and file it with FERC.

On February 10, 2004, FERC issued an order granting RTO status to SPP subject to the fulfillment of certain requirements.[5] In the order, FERC noted that while SPP has provided a framework for an IMM, FERC would still require SPP to make additional filings detailing the further specifics of its monitoring plan. First, FERC required that SPP develop a market monitoring plan that includes mitigation measures to address market power issues in spot markets and a set of rules establishing conduct for market

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[2] Regional Transmission Organizations 89 FERC ¶ 61,285 (December 1999) at p. 463.
[3] *Id.,* at p. 463.
[4] *Id.,* at p. 463-464.
[5] Southwest Power Pool 106 FERC ¶ 61,110 (February 2004).

participants and the consequences for violations of those rules. FERC noted that these mitigation measures should complement resource adequacy measures to ensure that the mitigation measures "do not suppress prices below the level necessary to attract needed investment in infrastructure in the region."[6]

FERC noted that at a minimum these mitigation measures would include rules on: "(1) physical withholding of supplies; (2) economic withholding of supplies; (3) reporting on availability of units; (4) factual accuracy of information submitted to the RTO or ISO; (5) the obligation of market participants to provide information to the market monitor; (6) cooperation of market participants in investigations or audits conducted by the market monitor, and (7) the requirement that all bids that designate specific resources must be physically feasible."[7]

Second, FERC pointed out that "guidance on the relationship between the IMM and the Commission" as discussed in the November 2003 Order Amending Market-Based Rate Tariffs and Authorizations (market behavior rules) should also be reflected in SPP's monitoring plan.[8] Third, FERC stated that SPP's monitoring plan should describe the process that the IMM would use if the "IMM thinks the markets are not resulting in just and reasonable prices or providing appropriate incentives for investment in needed infrastructure."[9] This process would involve notifying the FERC and other appropriate state authorities of the problems and recommended solutions. Fourth, the monitoring plan should provide for the issuance of periodic reports by the IMM, such as annual state of the market reports to FERC and state regulatory commissions. These reports would use "market metrics to provide a basis for measuring the performance of these markets across RTOs and ISOs, and to compare the performance of the market in each RTO or ISO over time…[and] on a monthly basis."[10]

Lastly, in support of SPP's cost and benefit analysis to develop the market functions associated with Phase 2 (market-based congestion management) and Phase 3 (ancillary services market), FERC states that the IMM should report on the "efficiency of current redispatch procedures to manage congestion to identify the costs that could be reduced using more efficient redispatch procedures in time to be considered when evaluating the Phase 2 design."[11]

(Going forward, the requirements include those reflected in any modification to FERC Orders.)

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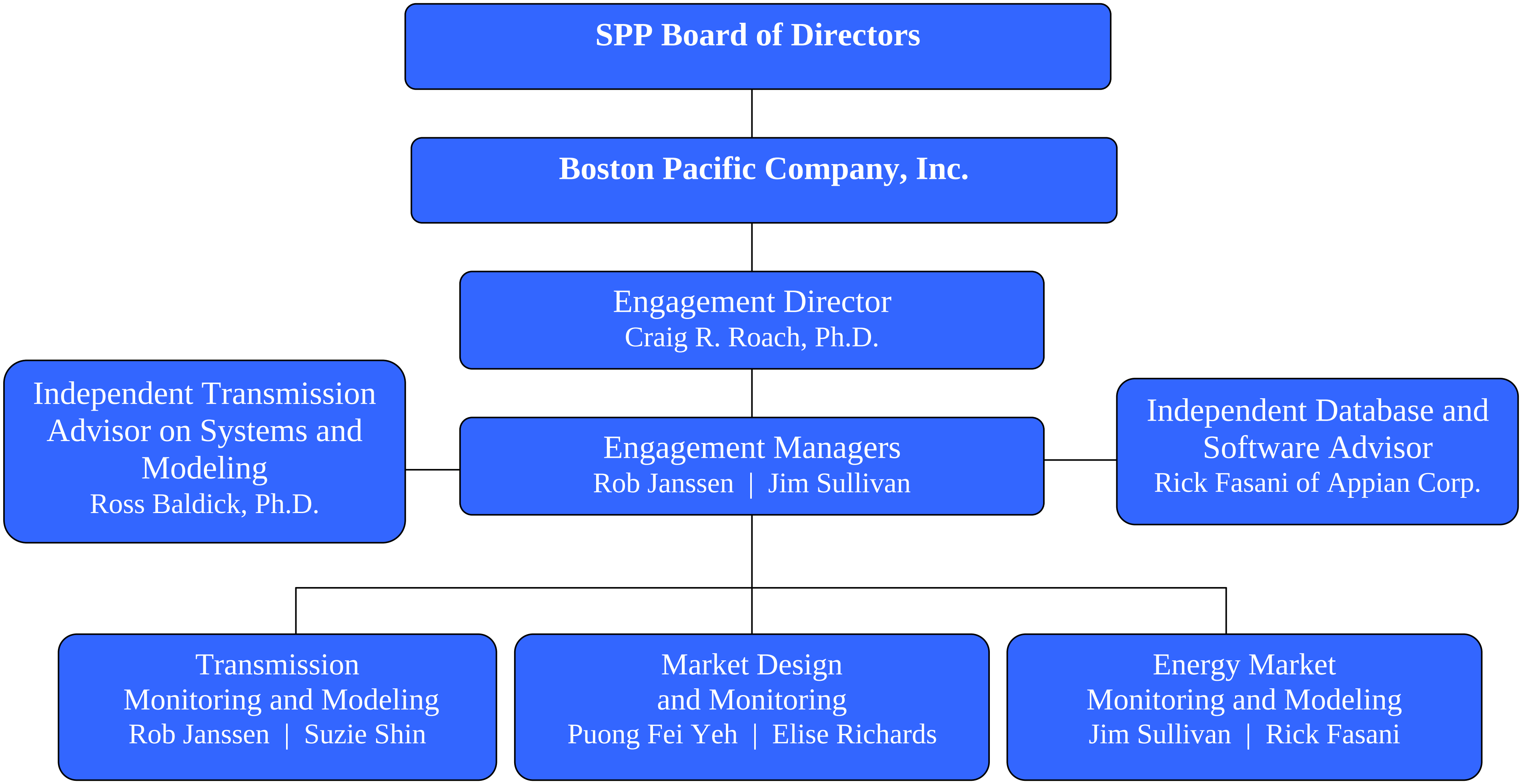
[6] *Id.*, at fn. 219.
[7] *Id.*, at fn. 220. These seven rules were also set forth in the FERC's April 28, 2003 White Paper on Wholesale Power Market Platform.
[8] *Id*.
[9] *Id.*, at p. 56.
[10] *Id.*, at p. 56.
[11] *Id.*, at p. 56.

BOSTON PACIFIC TEAM STRUCTURE



ATTACHMENT C- ONE
CODE OF ETHICS
FOR THE SPP IMM ENGAGEMENT

It is understood that credibility is crucial to the success of any independent market monitor (IMM) and that, to be credible, the IMM must be impartial in its investigations, findings, and recommendations. That is, the IMM must not favor one SPP Member over another or be influenced improperly by any SPP Member. The purpose of this code of ethics is to reinforce the commitment to impartiality. Therefore, while an employee of (or subcontractor for) Boston Pacific Company, Inc, I will adhere to the following standards:

1. I will abide by all provisions of the SPP IMM Services Agreement and this Code of Ethics throughout the term of the SPP IMM Services Agreement;

2. I will not advise anyone about whether or how to participate in any SPP market(s) for energy, capacity, or ancillary services or on whether and how to secure transmission service within the SPP footprint, other than as required in my role as the SPP IMM;

3. I will not work on any engagement related to the electricity business within the SPP footprint without the approval of the SPP Board of Directors or its delegate;

4. I will not appear for or against a SPP Member before a state regulatory commission within the SPP footprint in any new engagement in the electricity business except as required by my role as the SPP IMM or as requested by the state regulatory commission;

5. I will not appear for or against a SPP Member before the Federal Energy Regulatory Commission (FERC) on any matter within the SPP footprint in any new engagement in the electricity business except as required by my role as the SPP IMM or as requested by the FERC;

6. I will be impartial in my evaluation of the conduct of each SPP Member and each market rule. That is, I will weigh all points of view and all available evidence when coming to a decision, and will not show preferential treatment to any one SPP Member over another in any work done as the SPP IMM;

7. I will not willfully divulge to any unauthorized person any confidential information obtained in my work as the SPP IMM;

8. I will not allow any engagement or personal and/or professional relationship to impair my impartiality as the SPP IMM;

9. Any engagement with a SPP Member outside the SPP footprint will be done at my firm's standard rates and terms; and

10. I will not hold a direct financial interest in any SPP Member or affiliate of a SPP Member, that is involved in the electricity business.

Acknowledged and Agreed:

________________________________ ____________________

Employee Name (or Subcontractor) Date

Southwest Power Pool

Southwest Power Pool, Inc.

MARKETS & OPERATIONS POLICY COMMITTEE

Report to Board of Directors

July 27, 2004

Changes to Criteria 7

Background

Changes made throughout Criteria 7 because of working group name changes.

Changes made throughout Criteria 7 for grammar corrections.

7.1.1 changed to comply with NERC recommendations stemming from the August, 2003 Blackout Report

7.1.2 changed to clarify when DME will be required

7.3.1.3 changed to clarify the amount of load that should be shed in an UF event

7.5.6 Deals with Undervoltage, but the acronyms used were for underfrequency. Also changed when undervoltage data would be required from the Facility owners.

7.6.6 States when Facility owners will provide updates about ARL equipment to SPP and when the SPCWG will update the ARL Criteria.

Analysis

The above changes are needed to bring Criteria 7 into compliance with the NERC recommendations stemming from the August 2003 Blackout Report, to correct grammar errors, and to change working group names.

Recommendation

The MOPC recommends that the Board of Directors approve these changes to Criteria 7.

Approved:	SPCWG	June 3, 2004
	MOPC	July 14, 2004
Action Requested:	Approve the MOPC Recommendations	
Attachment:	Criteria 7 with changes	

7.0 SYSTEM PROTECTION EQUIPMENT

7.1 Disturbance Monitoring Equipment

'Disturbance Monitoring Equipment' (DME), as the term is used in this Section, refers to equipment such as Digital Fault Recorders (DFR), Sequence of Events Recorders, Phase Angle Monitors and other devices connected to the power system for the purpose of monitoring performance of the system. This equipment is used to capture data during disturbances defined as (i) any perturbation to the power system, or (ii) the unexpected change in the power system that is caused by the sudden loss of generation, transmission or interruption of load. Digital fault recorders are capable of producing fault records, consisting of instantaneous values of power system quantities collected many times per cycle, for a specific period of time. Disturbance monitoring devices collect and store (a) "fault data" from a line or equipment trip for abnormal conditions, or (b) "disturbance data" for power system performance swings or deviations outside of a predefined operating range (frequency, voltage, current, power, transients, etc.). Sequence of Events Recorders (SER) capture and time stamp events in the sequence in which they occur. The facility owner should be responsible for interpreting the information from SER's due to the equipment specific and detailed nature of these records. Typically, SER's record the sequence of breaker operations needed for higher-level event reconstruction and analysis. Information provided by SER's may be obtained from other devices such as fault recording equipment, SCADA, or other real time computer records.

7.1.1 Minimum Technical Requirements

Disturbance Monitoring Equipment, as a minimum, must be capable of producing time stamped event records (some pre-fault and some post-fault data) including waveforms for voltages and currents as well as power circuit breaker position indications. Sequence of Events Recorders may not be required as long as an appropriate monitoring device provides breaker indication. All new DME as required in 7.1.2 and 7.1.4 shall be synchronized to the National Institute of Standards and Technology time. All 230kV and above substations with DFRs that have the capability to be upgraded with time synchronization shall be upgraded by December 31, 2005 to use the National Institute of Standards and Technology synchronized time.

DME shall be capable of recording 5 events of not less than 30 cycles in duration with a sampling rate of 64 samples per cycle. Event data shall be retrievable for a period of not less than 72 hours. A minimum of three (3) cycles of pre-disturbance data shall be recorded with each event. DME shall record, at a minimum, the quantities listed below.

1) One set of voltages for each operating voltage at 100 KV and above in a substation. A set of voltages shall consist of each phase voltage waveform. If potential devices are not required for protection or metering purposes at a particular voltage level, then this particular voltage level need not be monitored.
2) For all lines, either three phase current waveforms or two phase current waveforms and neutral (residual) current waveform.
3) For all autotransformers, current waveform for three phases and either neutral/residual current waveform or current waveform in delta windings.
4) Status – circuit breaker trip circuit energization.
5) Status – carrier transmit/receive if carrier relaying is used.
6) Date and time stamp.

Regarding event triggering thresholds, quantities as derived from SPP or members' studies, when available, shall be used in lieu of those defined below. If none are clearly defined from load flow and stability studies, then the following requirements shall be used as a guide:

1) Phase current greater than or equal to 150% of the equipment rating.
2) Neutral (residual) current greater than or equal to 20% of the rating of the equipment.
3) Voltage excursions greater than or equal to 10% from operating range of equipment.

7.1.2 Required Location for Monitoring Equipment

Disturbance Monitoring Equipment will be required at all new EHV substations, operated at 345kV or higher, and all new generating stations of 400 MVA or greater placed in service after January 1, 2002. In addition, any new substation placed in service after January 1, 2002 containing six (6) or more lines operating at 100 KV and above will be required to have DME. However, when additional lines ~~are added to a substation~~ placed in service after January 1, 2002 are added to an existing substation that results in six (6) or more total lines, then DME shall be required for monitoring all elements within the substation as defined in 7.1.1. These requirements ~~will~~may be waived at SPP's discretion, if DME is already located at an adjacent substation. The number, type and location of disturbance monitoring equipment will normally be the responsibility of the facility owners based on recommendations by the owners' studies and this criteria. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in a database by the SPP staff for a period of at least three (3) years. The SPP System Protection and Control Working Group (SPCWG) shall monitor this database. The Transmission Assessment Working Group and ~~Security~~Operating Reliability Working Group will review the database to recommend that equipment with adequate capabilities, including digital fault recorders, be installed at critical locations throughout the system as determined in power flow and dynamic stability studies.

7.1.3 Requirements for Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality of the Disturbance Monitoring Equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. For newer DME's with self-monitoring, having SCADA reporting for a DME failure, and with successful downloading of events occurring at least annually, then such activity and application shall satisfy the testing and maintenance procedure requirements. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.1.4 Periodic Review of Disturbance Monitoring Equipment

SPP members shall maintain a list of substations where Disturbance Monitoring Equipment is located for generation and transmission facilities including those designated as being critical by the Transmission Assessment and Security Working Groups. The facility owner shall be responsible for providing required data on a form developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP upon request. The SPP staff will maintain and update the Disturbance Monitoring Equipment database. The Transmission Assessment and ~~Security~~Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.1.2. The SPCWG will update, if necessary, th~~e~~is S~~s~~ystem P~~p~~rotection E~~e~~quipment C~~c~~riteria every three (3) years.

7.1.5 Requests for Disturbance Data and Retention Requirements

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility owners shall provide requested equipment lists and disturbance data within 30 business days with a copy of the requested information forwarded to the SPP. SPP shall provide installation and reporting requirements to other regions and NERC within five (5) business days. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

A narrative description of each disturbance, pursuant to the requirements of SPP Criteria 11 addressing System Disturbance Reporting, to be provided by the facility owner shall include, at a minimum, a brief description of the event as identified on a form supplied by SPP. Additional items that shall be included are the cause of the incident, its consequences, service interrupted, corrective actions taken and any other additional actions that may be required beyond the point in time when the analysis is completed to include when these actions will be completed. Attachments shall be provided including relevant information from the DME that substantiates the determination of cause(s) of the disturbance. This information shall include all quantities based on the equipment requirements specified in 7.1.1, Minimum Technical Requirements. Facility owners shall retain disturbance data for a period of not less than one (1) year in a common format to the extent possible given the different manufacturers and types of equipment. However, the units of the data and source such as line, transformer and generator terminal shall be clearly identifiable in a consistent, time-synchronized format.

7.2 Transmission Protection Systems

7.2.1 Introduction

The goal of Transmission Protection Systems (TPS) is to ensure that faults within the intended zone of protection are cleared as quickly as possible. When isolating an electrical fault or protecting equipment from damage, these protection systems should be designed to remove the least amount of equipment from the transmission network to preserve electric system integrity. They should also not erroneously trip for faults outside the intended zones of protection or when no fault has occurred. The need for redundancy in protection systems should be based on an evaluation of the system consequences of the failure, misoperation of the protection system, and the need to maintain overall system reliability. All reviews of facilities as included in Criteria 7.2 shall be for those operated at 100kV or above.

7.2.2 Protection System Review

7.2.2.1 Assessment Of System Performance

The transmission or protection system owners shall provide an assessment of the system performance results of simulation tests of the contingencies in Table I of Standard I.A. (NERC Planning Standard). These assessments should be based on existing protection systems and any existing backup or redundancy protection systems to determine that existing transmission protection schemes are sufficient to meet the system performance levels as defined in NERC Standard I.A. and associated Table I. Therefore, the relative effects on the interconnected transmission systems due to a failure of the protection systems to operate when required versus an unintended operation should be weighed carefully in selecting design parameters. All non-compliance findings shall be documented including a plan for achieving compliance. These assessments should be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems within 30 days of the request.

7.2.2.2 Reviews Of Components And Systems

The owner shall conduct periodic reviews of the components and systems that make up the transmission protection system to assure that components and systems function as desired to minimize outages. All non-compliance findings, as a result of this review, shall be documented including a plan for achieving compliance. These reviews are to be completed as system changes dictate, or more frequently as needed based on misoperations as identified in Criteria 7.2.4. The reviews should include, but not be limited to, the following items:

1) Review of relay settings.
2) Current carrying capability of all components (Lines, CTs, breakers, switches, etc.).
3) Interrupting capability of all components (breakers, switches, fuses, etc.).
4) Breaker failure and transfer trip schemes.
5) Communications systems used in protection.

Models used for determining protection settings should take into account significant mutual and zero sequence impedances. The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance. Generation and transmission protection systems should avoid tripping for stable power swings on the interconnected transmission systems. Automatic reclosing or single-pole switching of transmission lines should be used where studies indicate enhanced system stability margins are necessary. However, the possible effects on the systems of reclosure into a permanent fault need to be considered. Protection system applications and settings should not normally limit transmission use. Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible. Communications systems used in protection should be either continuously monitored or alarmed, or automatically or manually tested.

7.2.3 System Redundancy

Transmission Protection Systems shall provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I (NERC). Each Transmission or Protection System Provider shall develop a plan for reviewing the need for redundancy in its existing transmission protection systems and for implementing any required redundancy. Documentation of the protection system redundancy reviews shall be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems, on request. Where redundancy in the protection systems (due to single protection system component failures) is necessary to meet the system performance requirements (of the I.A. Standards on Transmission Systems and associated Table I), the transmission or protection system owners shall provide, as a minimum, separate ac current inputs and separately fused dc control voltage with new or upgraded protection system installations. Breaker failure protections need not be duplicated.

Breaker failure protection systems, either local or remote, should be provided and designed to remove the minimum number of elements necessary to clear a fault while maintaining performance requirements. Physical and electrical separation should be maintained between redundant protection systems, where practical, to reduce the possibility of both systems being disabled by a single event or condition. When two independent protection systems are required, dual circuit breaker trip coils should be considered. Where each of two protection systems are protecting the same facility, the equipment and communications channel for each system should be separated physically and designed to minimize the risk of both protection systems being disabled simultaneously by a single event or condition.

7.2.4 Monitoring, Analysis And Notification Of Misoperations

Each Transmission or protection system owner shall have a process in place for the monitoring, notification, and analysis of all transmission protection trip operations. Any of the following events constitute a reportable TPS misoperation:

1) Failure to trip – Any failure of a TPS to initiate a trip to the appropriate terminal when a fault is within the intended zone of protection of the device.
2) Slow Trip – A correct operation of a TPS for a fault in the intended zone of protection where the relay system initiates tripping slower than the system design intends.
3) Unnecessary Trip During a Fault – Any relay initiated operation of a circuit breaker during a fault when the fault is outside the intended zone of protection.
4) Unnecessary Trip Other Than Fault – The unintentional operation of a TPS which causes a circuit breaker to trip when no system fault is present. This may be due to vibration, improper settings, load swing, faulty relay, or human error.
5) Failure to Reclose – Any failure of a TPS to automatically reclose following a fault if that is the intent.

Misoperations at lower voltages that cause an outage of a transmission component, operated at 100kV or higher, shall be reported. An operation of a TPS that only has an effect on a non-transmission component operated at less than 100kV need not be reported. Documentation of all protection trip misoperations shall be provided to SPP and NERC within five (5) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all TPS trip operations. It shall also provide consistent documentation of all TPS trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form supplied by SPP. When requested, supporting documentation shall be provided to SPP and include all fault and sequence of events data relevant to the cause of the misoperation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all trip misoperations.

7.2.5 Transmission Protection System Maintenance And Testing Programs

Facility owners shall have a protection system maintenance and testing program in place. The facility owner shall demonstrate full compliance to the program for protection system maintenance and testing and that all required activities have been completed on schedule. The program shall be maintained and documented. The facility owner will be responsible for maintaining and providing required data for each facility. Each facility owner will provide updates to SPP or NERC within 30 days of a request. Each facility owner shall periodically test the protection system components and system on a frequency as needed to assure that the system is functional and correct. Protection System component maintenance and testing shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. For newer TPS with self-monitoring, having SCADA reporting for a TPS failure, and with successful downloading or viewing of data following operations, then such activity and application shall satisfy the testing and maintenance procedure requirements. The facility owner shall maintain the documentation of all maintenance and tests records for one test period. Protection systems and their associated maintenance and testing procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation or inadvertent disabling. Protection and control systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design. The maintenance and testing program of the protection system should include provisions for relay calibration, functional trip testing, communications system testing, and breaker trip testing. All maintenance and testing shall be documented as described below:

1) Transmission protection system identification.
2) Summary of testing procedures.

3) Frequency of testing.
4) Date last tested.
5) Results of last testing.

7.2.6 Requests for Transmission Protection Systems Data

SPP shall function as a requesting agent and clearinghouse for the collection of TPS data on an as-needed basis. Facility owners should provide the requested data within thirty (30) days with a copy of the requested information forwarded to the SPP. If a facility owner cannot provide the requested data within this specified time frame, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.2.7 Transmission Protection Systems Criteria Updates

The SPCWG will update, if necessary, th~~e~~is Transmission Protection Systems ~~criteria~~Criteria every three (3) years.

7.3 UNDER-FREQUENCY LOAD SHEDDING AND RESTORATION

7.3.1 Automatic Load Shedding

A major disturbance among the interconnected bulk electric system may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. The areas of separation are unpredictable. To provide load relief and minimize the probability of network collapse the following practices are established.

7.3.1.1 Operating Reserve

All SPP operating reserve shall be utilized before resorting to shedding firm load. During a period of declining frequency, there may be violent swings of both real and reactive power. For this reason, all generator governors and voltage regulators shall be kept in automatic service as much as practical.

7.3.1.2 Operating Principles

a. To realize the maximum benefit from a load shedding program the points at which the load is shed in a company area shall be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

b. The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining frequency. The only practical way to remove load from a member in an attempt to stabilize the frequency is to do so automatically by the use of under-frequency relays. Since a geographical area or the timing of a period of low frequency cannot be predicted, all of the designated under-frequency relays on a member system shall be in service at all times. Underfrequency relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

c. The accepted practice of the electric industry is to shed load in a minimum of three steps. Should the frequency continue to decline after these three steps of load shedding, additional action may be required to protect generating machinery from mechanical damage. The actions may include opening of tie-lines, removal of generating units from the bus, additional steps of load shedding, or "island" operation may be utilized automatically with enough load left on a machine or plant to keep it in operation. A member can elect to use any one or a combination of these actions. It is recommended that this operation be performed at 58.5 Hz. Whatever is done by any one member shall be coordinated with neighboring members. A map or chart which shows additional actions that will be taken below a frequency of 58.7Hz shall be furnished to SPP.

7.3.1.3 Implementation

a. Should the utilization of spinning reserve fail to stop a frequency decline, load shedding shall be initiated in steps as indicated below. The goal of the program is to prevent a cascading outage due to a frequency excursion and restore the system to a stable condition. Members must be ready to shed, in three steps, thirty (30) percent of a member's current load regardless of the starting load point (i.e. peak-load, shoulder-load, low-load). This requirement shall be achieved as follows: 1) A member may dynamically arm and disarm UFLS relays to achieve the required load shedding totals, indicated in the chart below, by utilizing a load following program. For the purposes of this section, the term 'dynamically' means that no operator intervention is required to arm or disarm a UFLS relay, **or** 2) A member that does not dynamically arm and disarm UFLS relays shall install, or have installed on its behalf, UFLS relays with a total capability of shedding a minimum of thirty (30) percent of the member's current ~~projected summer peak~~ load. ~~.~~ The relays shall be set to shed the thirty (30) percent total in increments of ~~projected~~ current ~~peak~~ load per step, as indicated in the chart below. Once installed, these UFLS relays shall remain in service to trip loads except for periods of testing and maintenance.

Regardless of the technique utilized only the non-intentional delays including operating times of relays and breakers, plus any intentional delay as allowed in Criteria 7.3, shall delay the interruption of pre-event load for all events at the time of each event.

Step	Frequency (hz)	Minimum Load Relief (%)
1	59.3	10
2	59.0	10
3	58.7	10

b. The relays used to accomplish load shedding shall be high speed with no external intentional time delay devices employed. An exception to this policy would be on circuits serving considerable motor load (such as oil field or irrigation pumping load) which would cause the under-frequency relays to incorrectly operate when the source voltage is removed momentarily due to a transmission line fault.

c. Some members may elect to shed more than 10% of the system load on any step, particularly, if they have an adverse ratio of load responsibility to generating capability. This situation is not general and shall be considered on the merits of specific cases.

d. The tripping of any generating unit by under-frequency relays or any other protective device during low frequency conditions shall be so coordinated that these units will not be tripped before the three steps of load shedding have been utilized. Should this not be practical due to the operating characteristics of certain units, then these members shall protect the interconnected systems by shedding a block of load equal to the capability of the generating unit that will be tripped and at the frequency which will remove the unit from service. If the unit is jointly owned, each of the joint owners shall shed a block of load equal to their share of the unit.

e. The coordination among members becomes critical when actions beyond Step 3 are utilized; particularly, on those members which have established extra high voltage (EHV) terminals as part of their transmission system and/or with generators connected directly to the EHV system. Careful consideration shall be given when opening only one end of an EHV line section which is energized; the open-ended voltage could rise to damaging levels and reactive flow towards the closed-end could have intolerable effects. Further, if generation is connected to the affected portion of the EHV network, that generating capability would be removed from an area where it is sorely needed. Consideration shall be given to the coordination of under frequency relaying of the EHV transmission to maintain generating units on line and if necessary, carry portions of a neighboring system load to do so. System operators shall be alert to the effects of unloading the EHV network and be prepared to remove portions of the network should the voltage rise to intolerable levels.

7.3.1.4 Required Location And Model Data Reporting For Under-frequency Load Shedding Equipment

The number, type and location of Under-frequency Load Shedding (UFLS) equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in databases by the SPP staff for a period of at least three (3) years. These modeling databases shall be monitored as necessary by the SPP System Protection and Control Working Group (SPCWG). The Model Development Working Group, Transmission Assessment Working Group and ~~Security~~Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities is installed at critical locations throughout the system as determined in power flow and dynamic stability studies.

The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, location, breaker, trip frequencies, amount of load shed by trip frequency, relay and breaker operating times, and any intentional delay of breaker clearing. Also required will be any related generation protection, tie tripping schemes, islanding schemes, or any other schemes that are part of or impact the UFLS programs.

7.3.1.5 Requirements for Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means (i.e. self-testing microprocessor relays) to periodically check the functionality and availability of the UFLS equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.3.1.6 Periodic Review of Under-frequency Load Shedding Equipment

SPP members shall maintain a list of substations where UFLS equipment is located for all areas including those designated as being critical by the Transmission Assessment and ~~Security~~Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP ~~on an annual basis or~~ as requested. The SPP staff will maintain and update the UFLS equipment database. The Transmission Assessment and ~~Security~~Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.3.1.4. The SPCWG will update, if necessary, th~~e~~is UFLS ~~criteria~~Criteria every three (3) years.

7.3.1.7 Requests for Under-frequency Load Shedding Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners should provide the requested data within five (5) business days with a copy of the requested information forwarded to the SPP. However, it is recognized that significant disturbances may result in a large amount of equipment operations at multiple locations and that some equipment operations must be manually retrieved from the UFLS equipment's locations. These factors may make it impractical to retrieve and properly prepare the records and documentation within five (5) business days. In these cases, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.3.1.8 Restoration

After the frequency has stabilized the following procedure shall be followed.

a. In the event the frequency stabilized below 60 Hz, system operators shall coordinate operations to utilize all available generating capacity to the maximum extent possible in order to restore the frequency to 60 Hz. Deficient systems shall continue to shed load until the frequency can be restored to normal.

b. At 60 Hz the isolated areas shall be synchronized with the remainder of the interconnected systems. Synchronization between individual members shall be performed only upon direct orders of the system operators of both companies involved.

c. System operators shall coordinate load restoration as generating capability, voltage levels and tie-line loadings allow.

d. Any shed load shall be restored only upon direct orders of the system operator. Extreme care shall be exercised as to the rate at which load is restored to the system in order that limits of generation and transmission line loading are not exceeded. Insofar as possible, supervisory control shall be used to restore load; otherwise, manual restoration is preferable to insure positive control by the system operators.

e. It is recommended that a restoration plan be furnished by each company for use by its system operators for implementation of a coordinated and successful recovery.

7.3.2 Requirements of a Regional Under-frequency Load Shedding Program

The SPP shall develop, coordinate, and document a Regional UFLS program

7.3.2.1 SPP's Coordination of Under-frequency Load Shedding Program

This program shall coordinate UFLS programs within the sub-regions, Region, and where appropriate, among Regions. It shall also coordinate the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration. For an effective plan, SPP shall coordinate programs including generation protection and control, under-voltage load shedding, Regional load restoration, and transmission protection and control. Details to be included shall include those specified in 7.3.1.4. SPP shall periodically conduct and document a technical assessment of the effectiveness of the design and implementation of its UFLS program. The first technical assessment of the program shall be completed by SPP no later than June 1, 2001. These assessments shall be completed at least every five years thereafter or as required by significant changes in system conditions. The documented results of such assessments shall be provided to NERC on request.

7.3.2.2 Coordination of Under-frequency Load Shedding Programs And Analyses With SPP

The facility owners and operators of an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements including automatically shedding load in the amounts and at the locations, frequencies, rates and times consistent with those Regional requirements. When an under-frequency event occurs which is below the initializing set points of their UFLS programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.3.1.7.

7.3.3 Manual Load Shedding

A situation can arise when a control area must reduce load even though the frequency is normal. Since an automatic load shedding program will be of no avail in this case, manual load shedding procedures shall be utilized. One of the basic principles of interconnected operation is that a control area will match the area generation to area load at 60 Hz at all times. Should a generation deficiency develop for any reason, arrangements shall be made with adjacent control areas to cover the deficiency; but failing this, the affected control area shall reduce the area load until the available generation is sufficient to match it. In some cases a generation deficiency can be foreseen and will develop gradually; whereas, in other cases the deficiency will develop immediately with no forewarning. A gradually developing deficiency can probably be offset by using conservation procedures; whereas, an immediate deficiency will probably require customer service interruption. The importance of a load reduction plan cannot be overemphasized. A plan is offered here which can be modified to fit individual cases.

7.3.3.1 Conservation

a. Interruption of service to interruptible customers. Utilize to the extent that the situation requires.

b. Reduction of load in company facilities.

c. Reduction of distribution voltage level. Utilize to the extent possible and as the situation requires.

d. Load reduction by request to company employees and general public. The company employees and the general public shall be notified through news media to curtail the use of electricity.

e. Load reduction by request to bulk power users. Concurrent with voltage reduction and asking employees and the general public to reduce load, bulk power users (municipals and cooperatives) will be asked to reduce load in their areas using the same methods.

f. Load reduction by large use customers. Large use commercial and industrial customers will be requested to curtail electric power usage where such curtailment will not seriously disrupt customers' operations.

7.3.3.2 Service Interruption

Manual load interruption shall be implemented by a pre-determined plan, an example of which follows.

a. Each company operating subdivision shall select distribution circuits in approximately 5% increments in the order of their priority that will be taken out of service. The 5% increments will be labeled "A", "B", "C", "D", "E", and "F". The interruption and the restoration of these circuits will be under the control of the system operator. When the system operator determines that load must be reduced, he shall direct the subdivision operators to open all "A" circuits. This will reduce the system load 5%. If further load reduction is necessary, the system operator shall direct all "B" circuits to be opened which will result in an additional 5% reduction. This shall continue through "C", "D", "E", and "F" until the generation deficiency is eliminated.

b. The objective of this plan is to have no circuits open more than two hours. If the duration of the system emergency exists in excess of two hours and only the "A" circuits have been opened, then at the end of two hours the "B" circuits shall be opened and the "A" circuits reclosed. If a 10% reduction is necessary, "C" and "D" circuits shall be opened and "A" and "B" reclosed, after "A" and "B" have been open for two hours. Obviously, no circuits shall be open longer than is absolutely necessary. The "E" and "F" circuits shall be opened to avoid opening "A" and "B" circuits twice in one day.

c. When a generation deficiency develops, or begins to develop, the system operator shall alert all involved operating personnel to the effect that certain circuits may have to be interrupted. This action will reduce the time required to execute circuit interruption orders of the system operator. Some control areas in SPP have extensive supervisory control systems while others have little, if any, supervisory control. Obviously, any implementation plan shall make best use of available equipment.

7.4 Special Protection Systems Equipment

A Special Protection Systems (SPS) or Remedial Action Scheme (RAS) is designed to detect abnormal system conditions and take automatic pre-planned, coordinated, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings. All reviews of facilities as included in Criteria 7.4 shall be for those used to monitor and control transmission facilities operated at 100kV or above.

The SPS design shall not create cascading transmission outages or system instability. One possible SPS may be the automatic and sequential dropping of load, generation, or adjacent high voltage (HV) lines, if a HV line trips. A SPS does not include (a) underfrequency load shedding or undervoltage load shedding as they are addressed under NERC Planning Standards III.D, Criteria 7.3, and III.E or (b) fault conditions that must be isolated or (c) out-of-step relaying. The SPS shall not require operator action, and all actions of the SPS are automatic. SPS shall be automatically armed without human intervention when appropriate. The status indication of any automatic or manual arming of SPS shall be provided as SCADA alarm inputs.

7.4.1 Operating Requirements and System Redundancy

Special Protection Systems shall include redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of NERC I.A. Standards on Transmission Systems in Categories A, B of C of the associated Table I. Each facility owner shall develop a plan for reviewing the need for redundancy in its existing special protection systems and for implementing any required redundancy. Documentation of these reviews shall be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems, on request. Also, the misoperation, incorrect operation, or unintended operation of an SPS when considered by itself and not in combination with any other system contingency shall meet the system performance requirements as defined under Category C of Table I of the NERC I.A Standards on transmission systems.

7.4.2 Location And Data Reporting For Special Protection Systems Equipment

The number, type and location of SPS equipment will normally be the responsibility of the facility owners based on recommendations by the owners' and SPP's studies. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in databases by the SPP staff for a period of at least five (5) years. These databases shall be monitored as necessary by the SPP System Protection and Control Working Group (SPCWG). The Transmission Assessment Working Group and ~~Security~~Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities be installed at critical locations throughout the system as determined in power flow and dynamic stability studies. The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall represent the designed functionality of the system. Documentation by facility owners for each SPS utilized shall include details on its design, its operation, its control, its functional testing, and coordination with other schemes that are part of or impact the SPS.

7.4.3 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality of the SPS equipment in service. Component testing and maintenance shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests and maintains on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for one testing period. SPS shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design. Each facility owner will provide updates to the SPP or NERC upon request.

7.4.4 Periodic Review of Special Protection Systems Equipment

SPP members shall maintain a list of substations where SPS equipment is located for all areas including those designated as being critical by the Transmission Assessment and ~~Security~~Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the SPCWG and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the SPS equipment database. The Transmission Assessment and ~~Security~~Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.4.2. The SPCWG will update, if necessary, th~~e~~is SPS ~~criteria~~Criteria every three (3) years.

Based upon (a) a five year interval or other interval as required by electric system changes, or (b) if a new SPS, or (c) if a modified SPS, each facility owner will review and document their SPS for compliance with Regional planning criteria and guides, and the NERC Planning

Standard I.A including the associated Table I. This review shall include system studies to evaluate the consequences of: 1) the proper operation of the SPS, 2) the failure of an SPS to operate due to a single component failure of the SPS, and 3) the misoperation, incorrect operation, or the unintended operation of an SPS when considered by itself without any other system contingency. These consequences shall not include cascading transmission outages or system instability. These studies shall include the date that they were performed, who performed them, the methodology of the study, the results of the study, and when the next study is anticipated.

7.4.5 Requests for Special Protection Systems Data.

SPP shall function as a requesting agent and clearing house for the collection of SPS data on an as-needed basis. Facility owners should provide the requested data within thirty (30) days with a copy of the requested information forwarded to the SPP. If a facility owner cannot provide the requested data within this specified time frame, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.4.6 Submittals Of Special Protection Systems Misoperations.

All misoperations of a SPS shall be reported to the SPP within five (5) business days after receipt of the request, or as soon as possible thereafter. Any of the following events constitute a reportable SPS misoperation:

1) Failure to Operate – Any failure of a SPS to perform its intended function within the designated time when system conditions intended to trigger the SPS occur.
2) Failure to Arm – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed.
3) Unnecessary Operation – Any failure of a SPS that occurs without the occurrence of the intended system trigger condition(s) including human error.
4) Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s).
5) Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions if that is the design intent.

Misoperations at lower voltages that cause an operation of a SPS, in systems 100kV or higher, shall be reported. A detailed analysis of the misoperation, its consequences, and the corrective actions taken to prevent a reoccurrence will be reported to the SPP within thirty (30) days. SPP shall be notified of any delay and the anticipated date of forwarding the required data. This analysis to be provided by the facility owner shall include, at a minimum, the description of facility as identified on a form, developed by the SPCWG and supplied by SPP, including a complete summary report of the misoperation, its consequences, corrective actions taken, and any other additional actions that may be required beyond the point in time when the analysis is completed to include when these actions will be completed. The analysis and corrective actions shall be reviewed by the SPCWG. If these reported corrective actions are deemed inadequate, then the corrective actions that SPP recommends shall be completed as soon as possible subject to equipment availability.

7.4.7 Submittals For New And Modified Special Protection Systems

The owner of the SPS shall notify SPP of its intent to construct a new or modify an existing SPS with sufficient lead time to allow for an orderly review by SPP's working groups and committees. This notification will include statements on whether misoperation or failure of the SPS would have local, inter-company, inter-area or interregional consequences, when the SPS is planned for service, how long it is expected to remain in service, what specific contingency(s) it is designed to operate for and whether the SPS will be designed according to all SPP operating requirements of the bulk transmission system and NERC Standards. For a new or modified SPS prior to construction of facilities, three (3) copies of all applicable studies supporting the design requirements of the SPS and three (3) copies of a complete set of electrical design specifications, drawings and operating plans shall be submitted to the SPP with this notification. The drawings shall include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The documentation of the proposed system will include any special conditions or design restrictions that exist in the proposed system.

The System Protection And Control, Transmission Assessment and ~~Security~~Operating Reliability Working Groups will assess the SPS's conformance with all SPP operating requirements of the bulk transmission system and NERC Standards. If necessary, the working groups will request that the facility owner conduct additional studies and provide additional details of design specifications, drawings and operating plans. The results of such compliance review shall be documented with all recommendations that are deemed appropriate by the SPP and forwarded to the requesting party normally within 120 days from the date of request. The recommendations of SPP shall be completely incorporated into the design of the SPS.

A presentation will be made to appropriate working groups when a facility owner deviates from any of the SPP operating requirements of the bulk transmission system and NERC Standards as well as when a member system is in doubt as to whether the design meets these requirements. The facility owner shall arrange for the technical presentation by advising SPP approximately four months prior to the presentation and by providing copies of the materials to be presented 30 days prior. The facility owner will advise appropriate working groups of the basic design of the proposed system and include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The proposed system should be explained with due emphasis on any special conditions or design restrictions that exist in the proposed system. A presentation will also be made to appropriate working groups relating to new facilities or a modification to an existing facility when requested by either a member system or a working group.

7.5 UNDERVOLTAGE LOAD SHEDDING

One characteristic of electric systems that experience heavy loadings on transmission facilities with relatively limited reactive power control is the susceptibility to voltage instability. Such instability can cause tripping of generation and transmission facilities resulting in loss of customer demand as well as collapse of the bulk transmission system. A major disturbance among the interconnected bulk electric systems may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. Since voltage collapse can occur rapidly, operators may not have sufficient time to stabilize the systems. Therefore, a load-shedding scheme that is automatically activated as a result of undervoltage conditions in portions of a system can be an effective means to stabilize the interconnected systems and mitigate the effects of a voltage collapse.

7.5.1 Program Participants

Facility Owners who determine it beneficial to install undervoltage load shedding (UVLS) equipment may do so. However, UVLS schemes must coordinate with all protection and underfrequency load shedding schemes for the reliable operation of facilities operated at 100kV and above. Also, members are not required to install such equipment unless deemed necessary by either SPP or NERC to ensure the reliability of bulk transmission systems.

7.5.2 Operating Reserve And Principles

All SPP operating reserve shall be utilized before resorting to shedding firm load. All generator governors and voltage regulators shall be kept in automatic service as much as practical so that generating units may be used to their maximum capability for supplying voltage support during disturbances.

a. To realize the maximum benefit from a load shedding program, the points at which the load is shed in a company area should be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

b. The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining voltage. One practical way to remove load from a member in an attempt to stabilize the voltage is to do so automatically by the use of undervoltage relays. All of the designated undervoltage relays on a member system shall be in service at all times. Undervoltage relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

c. Loads may be shed in multiple steps. Whatever actions are planned or implemented by one member, including actions other than load shedding, shall be coordinated with neighboring members and SPP. All UVLS programs shall coordinate with underfrequency load shedding requirements of other members and SPP to maintain the reliability of the bulk transmission system operated at 100kV and above.

d. Should the utilization of various assets, such as responsive voltage-supporting resources, generation, capacitors and static var systems, fail to stop a voltage decline, load shedding shall be initiated as determined by the member of which is conditional upon the regional requirements of SPP. The relays used to accomplish load shedding shall be high speed with the necessary external intentional time delay devices employed to eliminate nuisance trips during faults, reclosing delays, etc.

7.5.3 Location And Data Reporting

The determination of the number, type and location of UVLS equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies. Facility owners shall provide information about these installations to the SPP in accordance with NERC Standards within five (5) business days upon receipt of the request. This information will be maintained in databases by the SPP staff for a period of at least three (3) years. The SPP System Protection and Control Working Group (SPCWG) shall monitor these databases as necessary. The Transmission Assessment Working Group and ~~Security~~Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities be installed at critical locations throughout the system as determined in power flow and dynamic stability studies.

The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, type of equipment, location, breaker, trip voltages, amount of load shed by trip voltage, relay and breaker operating times, and any intentional delay of breaker clearing. Also required will be any related generation protection, tie tripping schemes, islanding schemes, or any other schemes that are part of or impact the UVLS programs.

7.5.4 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all UVLS trip operations. Any of the following constitute a reportable UVLS misoperation:

1) Failure to trip – Any failure of UVLS equipment to initiate a trip to the appropriate terminal when a voltage level is less than or equal to a low-voltage set point.
2) Slow Trip – A correct operation of UVLS equipment for a low-voltage condition where the relay system initiates tripping slower than the system design intends.
3) Unnecessary Trip With Acceptable Voltage – Any relay initiated operation of a circuit breaker when the voltage is within acceptable limits.
4) Unnecessary Trip Within Period Of Time Delay – Any relay initiated operation of a circuit breaker before an intended time delay has expired.

5) Unnecessary Trip, Other– The unintentional operation of a UVLS scheme which causes a circuit breaker to trip when no low-voltage condition is present. This may be due to vibration, improper settings, load swing, faulty relay, or human error.

Misoperations at lower voltages that cause an outage of a transmission component, operated at 100kV or higher, shall be reported. Documentation of all misoperations shall be provided to SPP and NERC within thirty (30) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all trip operations. It shall also provide consistent documentation of all trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form, developed by the SPCWG and supplied by SPP, with applicable attachments. These attachments shall include all voltage and sequence of events data relevant to the cause of the misoperation of which is the basis for the documentation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all trip misoperations.

7.5.5 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means (i.e. self-testing microprocessor relays) to periodically check the functionality and availability of the UVLS equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.5.6 Periodic Review of Undervoltage Load Shedding Equipment

SPP members shall maintain a list of substations where UV~~F~~LS equipment is located for all areas including those designated as being critical by the Transmission Assessment and ~~Security~~Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP ~~on an annual basis or~~ as requested. The SPP staff will maintain and update the ~~UFLS~~ UVLS equipment database. The Transmission Assessment and ~~Security~~Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.5.3. The SPCWG will update, if necessary, th~~e~~is UVLS ~~criteria~~Criteria every three (3) years.

7.5.7 Requests for Undervoltage Load Shedding Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all misoperations within the requested time frame, 2) an implemented maintenance program, and 3) an applicable technical assessment. SPP shall provide program information including equipment data to NERC within thirty (30) business days upon receipt of a request. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.5.8 Coordination of Undervoltage Load Shedding Programs

The facility owners and operators of an UVLS program shall ensure that their programs are consistent with Regional UVLS program requirements including automatically shedding load in the amounts and at the locations, voltages, rates and times consistent with those Regional requirements. When an undervoltage event occurs which is below the initializing set points of their UVLS programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in

7.5.7.

7.6 AUTOMATIC RESTORATION OF LOAD

Following a disturbance when the frequency and voltage have stabilized, properly coordinated and implemented programs for the automatic restoration of load can be useful to minimize the duration of interrupted electric service. However, the design of such plans must ensure that the automatic restoration of load does not impede the restoration of the interconnected bulk electric facilities operated at 100kV or higher. After the automatic shedding of load by either underfrequency or undervoltage relaying schemes has occurred, the interconnected bulk electric facilities must first be stabilized with regard to both nominal frequency and voltage within appropriate limits prior to arming an automatic restoration of load system. Also, sufficient spinning reserves must be available such that the recreation of an underfrequency or undervoltage condition does not occur when electric service is restored. Then automatic load restoration programs can be used to effectively expedite the restoration of electric service to accommodate customer demands.

7.6.1 Program Participants

Facility Owners who determine it beneficial to install equipment for the automatic restoration of load (ARL) may do so. However, ARL schemes must coordinate with all protection as well as underfrequency (UFLS) and undervoltage load shedding (UVLS) schemes for the reliable operation of facilities operated at 100kV and above while not overloading any of these facilities. Also, members who install such equipment shall meet all requirements of SPP and NERC to ensure that the reliability of bulk transmission systems is maintained.

7.6.2 Operating Reserve And Principles

Available spinning reserves within SPP and each control area must be sufficient to serve the load to be energized by ARL schemes before arming such schemes. To prevent the use of ARL schemes when insufficient spinning reserves are available, ARL schemes shall be armed by automatic generation control systems of which are operated by or are coordinated with the appropriate control area(s). All generator governors and excitation equipment including voltage regulators shall be kept in automatic service when ARL schemes are armed so that the spinning reserve of available generating units may be used to their maximum capability for supplying real and reactive power during restoration. Additional requirements for the application of programs involving the automatic restoration of load are listed below.

a. Whatever actions are planned or implemented by one member involving the automatic restoration of load shall be coordinated with other members, SPP and other Regions. All ARL programs shall coordinate with underfrequency and undervoltage load shedding programs as well as ARL programs of other members to maintain the reliability of the bulk transmission system operated at 100kV and above.

b. An ARL system shall not be armed unless all pre-designated conditions are satisfied within the control area unless a designated island or sub-area is specified. Unless removed from service for testing and maintenance purposes, an ARL system shall be automatically armed and remain so only when 1) indication that an UFLS or UVLS scheme has operated, 2) the governor and excitation systems of available generation are in the automatic mode, 3) spinning reserves of available generation are greater than or equal to the real and reactive power requirements of the pre-event load to be restored, adjusted to the forecasted daily load curve and changes in diversity, plus incremental losses, 4) an adequate system frequency has been achieved, 5) voltages throughout the transmission system are within valid limits, 6) all intended transmission system interconnects are closed, and 7) all intended breakers including those used for islanding are closed. However, operators of an island or control area that has separated from the remainder of the bulk transmission system may arm an ARL system for this specific area if 1) a neighboring system(s) has not achieved or maintained an adequate frequency or voltage levels within acceptable limits, and 2) all of the conditions specified above are met except that all intended transmission system interconnects or islanding breakers may not be closed.

c. The time intervals involved in the automatic restoration of loads is of extreme importance. The restoration of too much load at one or over time relative to the capacity of available generating units given their dynamic characteristics may result in an unstable system. Therefore, loads to be automatically restored over time shall not exceed the ramping capabilities of the available generation. Also, upon being armed, ARL equipment shall restore load in multiple blocks by design to minimize the possibility of causing an underfrequency or undervoltage condition.

d. When any portion of the generation required to serve restored load is physically separated from the load by facilities within another control area, then adequate facilities between the generation and load with sufficient capacity to transfer the power shall be verified and applicable breakers shall be closed before the ARL system is armed.

e. Only those loads interrupted by UFLS and UVLS schemes may be restored by ARL equipment. Therefore, if either a UFLS or UVLS scheme did not interrupt a given load, then the use of ARL equipment shall not be used to restore the load. When UVLS equipment is used to trip loads, then the local voltage shall be within acceptable limits before the local ARL equipment energizes the load.

f. The points at which the load is restored in a company area should be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be restored can be selected.

g. Should the utilization of spinning reserve fail to adequately stabilize either frequency or voltage in a control area or designated portion thereof after restoring service to loads, or portions thereof, controlled by ARL equipment, the ARL equipment of said area shall be automatically disarmed. ARL schemes shall be designed and installed to restore load only once before being rearmed manually or by system operators via SCADA.

7.6.3 Location And Data Reporting

The determination of the number, type and location of ARL equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies. The technical assessments of ARL applications conducted by or on behalf of the facility owner shall validate the coordination with underfrequency and undervoltage programs within SPP and other Regions as necessary. Facility owners shall provide information about these installations to the SPP in accordance with NERC Standards within five (5) business days upon receipt of the request. This information will be maintained in databases by the SPP staff for a period of at least three (3) years. The SPP System Protection and Control Working Group (SPCWG) shall monitor these databases as necessary. The Transmission Assessment Working Group and ~~Security~~Operating Reliability Working Group will review the databases as well as technical assessments conducted by facility owners and recommend that equipment with adequate capabilities be installed, or removed as necessary, at critical locations throughout the system as determined in power flow and dynamic stability studies.

The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, type of equipment, location, breaker, minimum voltage and frequency thresholds, amount of load shed that is to be restored, relay and breaker operating times, and any intentional delay of breaker closing. Also required will be any related generation protection, tie-closing schemes, islanding schemes, or any other schemes that are part of or impact the ARL programs.

7.6.4 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all ARL closing operations. Any of the following constitute a reportable ARL misoperation:

1) Failure to close – Any failure of armed ARL equipment to initiate a close to the appropriate circuit breaker when a local voltage and/or frequency level is greater than or equal to applicable set points.
2) Slow Close – A correct operation of armed ARL equipment where the relay system initiates closing slower than the system design intends.
3) Unnecessary Close By Unarmed Equipment – Any initiated closing of a circuit breaker when all pre-designated conditions are not met.
4) Unnecessary Close, Other– The unintentional operation of an unarmed ARL scheme that causes a circuit breaker to close when no event had previously occurred. This may be due to vibration, improper settings, faulty relay, or human error.

Documentation of all misoperations shall be provided to SPP and NERC within thirty (30) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all trip operations. It shall also provide consistent documentation of all closing misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form, developed by the SPCWG and supplied by SPP, with applicable attachments. These attachments shall include all voltage, frequency and sequence of events data relevant to the cause of the misoperation of which is the basis for the documentation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all closing misoperations.

7.6.5 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality and availability of the ARL equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

ARL systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than three (3) years to verify the dependability and security aspects of the design. The maintenance and testing program of the ARL system should include provisions for relay calibration, functional trip testing, communications system testing, and breaker closure testing. All maintenance and testing shall be documented as described below:

1) Automatic Restoration of Load system identification.
2) Summary of testing procedures.
3) Frequency of testing.
4) Date last tested.
5) Results of last testing.

7.6.6 Periodic Review of Equipment

SPP members shall maintain a list of substations where ARL equipment is located for all areas including those designated as being critical by the Transmission Assessment and

~~Security~~Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP ~~on an annual basis or~~ as requested. The SPP staff will maintain and update the ARL equipment database. The Transmission Assessment and ~~Security~~Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.6.3. The SPCWG will update, if necessary, th~~e~~is ARL ~~criteria~~Criteria every three (3) years.

7.6.7 Requests for Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all misoperations within the requested time frame, 2) an implemented maintenance program, and 3) an applicable technical assessment. SPP shall provide program information including equipment data to NERC within five (5) business days upon receipt of a request. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.6.8 Coordination of Programs

The facility owners and operators of an ARL program shall ensure that their programs are consistent with Regional ARL program requirements including automatically restoring load in the amounts and at the locations, range of voltages and frequencies, rates and times consistent with those Regional requirements. When an undervoltage or underfrequency event occurs which initiates the utilization of ARL programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.6.7.

7.6.9 Submittals For New And Modified ARL Systems

The owner of the ARL system shall notify SPP of its intent to install a new or modify an existing ARL with sufficient lead time to allow for an orderly review by SPP's working groups and committees. This notification will include statements on whether misoperation or failure of the ARL system would have local, inter-company, inter-area or interregional consequences, when the ARL system is planned for service, how long it is expected to remain in service and whether the ARL system will be designed according to all SPP operating requirements of the bulk transmission system and NERC Standards. For a new or modified ARL system prior to installation of facilities, three (3) copies of all applicable studies supporting the design requirements of the ARL system and three (3) copies of a complete set of electrical design specifications, drawings and operating plans shall be submitted to the SPP with this notification. The drawings shall include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The documentation of the proposed system will include any special conditions or design restrictions that exist in the proposed system.

The System Protection And Control, Transmission Assessment and ~~Security~~Operating Reliability Working Groups will assess the ARL system's conformance with all SPP operating requirements of the bulk transmission system and NERC Standards. If necessary, the working groups will request that the facility owner conduct additional studies and provide additional details of design specifications, drawings and operating plans. The results of such compliance review shall be documented with all recommendations that are deemed appropriate by the SPP and forwarded to the requesting party normally within 120 days from the date of request. The recommendations of SPP shall be completely incorporated into the design of the ARL.

A presentation will be made to appropriate working groups when a facility owner deviates from any of the SPP operating requirements of the bulk transmission system and NERC Standards as well as when a member system is in doubt as to whether the design meets these requirements. The facility owner shall arrange for the technical presentation by advising SPP approximately four months prior to the presentation and by providing copies of the materials to be presented 30 days prior. The facility owner will advise appropriate working groups of the basic design of the proposed system and include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The proposed system should be explained with due emphasis on any special conditions or design restrictions that exist in the proposed system. A presentation will also be made to appropriate working groups relating to new facilities or a modification to an existing facility when requested by either a member system or a working group.

7.7 Generation Control and Protection

The objectives of protective relaying and control schemes within generation facilities are to promptly detect abnormal conditions and isolate or control equipment to minimize damage to equipment. Some of these abnormal conditions which will result in an alarm or tripping of generation include faults, overload, overheating, off-frequency, loss of field, motoring, single-phase or unbalance current operation, and out-of-step. The selection and settings of equipment should not result in erroneous tripping for acceptable operating conditions or for faults outside the intended zones of protection.

Generation Control and Protection Systems (GCP) must be coordinated with excitation and governor controls to minimize generator tripping during disturbance-caused abnormal voltage, current and frequency conditions. Therefore, protection and control schemes should be designed and installed with appropriate settings to provide a reasonable balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect the generator equipment from damage. All reviews, monitoring and analysis of each generator, rated at 20MW or above, shall be completed as described in Criteria 7.7.

7.7.1 Reviews Of Components And Systems

The owner shall conduct periodic reviews of the components and systems that make up the generation protection system to assure that components and systems function as desired to minimize outages. The design and implementation of all new protection schemes shall be in accordance with IEEE and ANSI Standards, Guides and Recommended Practices as well as NERC Standards and Guides. Should it be determined that the design and application of protection equipment do not adhere to such requirements, then these findings, as a result of this review, shall be documented including a plan for achieving the necessary results. These reviews are to be completed as system changes dictate, or more frequently as needed based on misoperations as identified in Criteria 7.7.2. The reviews should include, but not be limited to, the following items:

1) Review of relay settings.
2) Current carrying capability of all components (Bus, cables, lines, CTs, breakers, switches, etc.).

3) Interrupting capability of all components (breakers, fuses, etc.).
4) Breaker failure and trip schemes.

The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance. Generator protection systems should not operate for stable power swings except when that particular generator is out of step with the remainder of the system. Loss of excitation and out of step relays should be set with due regard to the performance of the excitation system.

All underfrequency, overfrequency, undervoltage and overvoltage protection systems shall be coordinated with system underfrequency and undervoltage load shedding schemes. Power plant auxiliary motors should not trip or stall for momentary undervoltage associated with the contingencies as defined in Categories A, B and C of NERC I.A Standards unless the loss of the associated generating unit(s) would not cause a violation of the contingency performance requirements.

Redundant generator protection schemes are required for all new generator installations and all re-powering projects where the generator is rated at 20MW or above. Redundant generator protection schemes for the step-up transformer and the main auxiliary transformer (if any) are not required but encouraged. Where redundant protection systems are being used, efforts should be made to use separate current transformers, potential transformers, and DC control power circuits to minimize the risk of both systems being disabled by a single event or condition.

The use of dual trip coils, if available, on both generator and unit circuit breakers are required for all new generator installations at 20MW or above. The installation of breaker failure relaying for generator and unit circuit breakers are also required for all new generator installations at 20MW or above. The addition of breaker failure relaying for all generator and unit circuit breakers at existing sites is not required but encouraged.

7.7.2 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all generation protection trip operations. Any of the following constitute a reportable misoperation of generation protection equipment and schemes:

1) Failure to trip – Any failure of a GCP to initiate a trip when required.
2) Slow Trip – A correct operation of a GCP slower than the system design intends.
3) Unnecessary Trip– The unintentional operation of a GCP that causes a unit's output to be significantly reduced or causes the unit to trip when not required. This may be due to any number of factors such as equipment failure, incorrect settings, and relay misapplication.

Misoperations occuring prior to synchronization need not be reported, but shall be investigated and corrected to prevent possible misoperations when the unit is synchronized to the system. Documentation of all protection misoperations shall be provided to SPP and NERC within thirty (30) business days of the request.

Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all GCP trip operations. It shall also provide consistent documentation of all GCP trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form supplied by SPP. When requested, supporting documentation shall be provided and include all fault, disturbance, load and sequence of events data relevant to the cause of the misoperation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform documentation format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all trip misoperations.

7.7.3 Generation Protection System Maintenance And Testing Programs

Facility owners shall have a protection system maintenance and testing program in place. The facility owner shall demonstrate full compliance to the program for protection system maintenance and testing, demonstrating that all required activities have been completed on schedule. The program shall be maintained and documented. The facility owner will be responsible for maintaining and providing required data for each facility. Each facility owner will provide updates to SPP or NERC within 30 days of a request.

The facility owner shall maintain the documentation of all maintenance and tests records for one test period. Protection systems and their associated maintenance and testing procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation or inadvertent disabling. Protection and control systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design.

Each facility owner shall periodically test the protection system components on a frequency as needed to assure that the system is functional and correct. The maintenance and testing of system components, i.e. relays, shall be completed based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation but at least every three (3) years. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. For newer GCP Systems with self-monitoring, having SCADA reporting for a GCP failure, and with successful downloading or viewing of data following operations, then such activity and application shall satisfy the testing and maintenance procedure requirements.

The maintenance and testing program of the protection system should include provisions for relay calibration, functional trip testing, and breaker trip testing. All maintenance and testing shall be documented as described below:

1) Generation protection system identification.
2) Summary of testing procedures.
3) Frequency of testing.
4) Date last tested.
5) Results of last testing.

7.7.4 Requests for Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all misoperations within the requested time frame, and 2) an implemented maintenance and testing program. SPP shall provide program information including equipment data to NERC within five (5) business days upon receipt of a request. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.7.5 Coordination of Programs

The facility owners and operators of a GCP program shall ensure that their programs are consistent with Regional GCP program requirements effective January 1, 2002. When a disturbance, fault, or misoperation occurs which initiates the utilization of GCP equipment and schemes, the owners or operators shall analyze and document the event. Documentation of all misoperations shall be provided to SPP and NERC on request in the time frames established in 7.7.4. Generator owners/operators shall have a generator protection system maintenance and testing program in place.

7.7.6 Generation Protection Systems Criteria Updates

The SPCWG will update, if necessary, this Generation Control and Protection Systems ~~criteria~~Criteria every three (3) years.

7.8 Generator Controls – Status and Operation

7.8.1 Generator Excitation System Control Operation

All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation systems in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved by the control area operator.

7.8.1.1 Reporting Procedures

Control Area Operators shall implement procedures that require Synchronous Generator Operator/Owners to provide information to the Control Area Operator, SPP, and NERC upon request (30 business days) concerning the generators' automatic voltage control regulator. The procedures shall include the following.

a. Summary report showing the number of hours each synchronous generator did not operate in automatic voltage control mode during each calendar month. Information shall be provided on the "Generator Owner/Operator Excitation System Summary Report" supplied by SPP, if control area operator does not have its own form.
b. Detailed reports of the date, duration, and reason for each instance in which a synchronous generator was not operated in the automatic voltage control mode for a specific calendar month. Information shall be provided on the "Generator Unit Excitation System Status Report" supplied by SPP, if control area operator does not have its own form.
c. The Generator Owner/Operator shall retain the reports mentioned in (a.) and (b.) for a period of 12 rolling months.

7.8.1.2 Exempt Generators

Control Area operators shall have criteria stating which generators may be exempt from these procedures. Exemptions shall include the following.

a. Generator output less than 20MW
b. Generation is of intermittent type or variety (wind generation)
c. Other criteria as control area operator deems appropriate.

7.8.2 Generator Operation for maintaining Network Voltage

Synchronous generators shall maintain a network voltage or reactive power output as required by the control area operator within the reactive capability of the units.

7.8.2.1 Control Area Responsibilities

a. Each control area operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator at a specified bus and shall provide this information to the generator owner/operator. Documentation of the information shall be provided on the "Generator Owner/Operator Voltage Schedule Requirements" report supplied by SPP, if the control area operator does not have its own form. This information shall be made available to SPP and NERC on request (30 business days).

b. Each control area operator shall maintain a list of synchronous generators that are exempt from the requirement of maintaining a network voltage or reactive schedule. The list of exempt generators shall be made available to SPP and NERC on request (30 business days) and shall be supplied on “Control Area Operator’s List of Exempt Generators” report supplied by SPP, if control area does not have its own form.

7.8.2.2 Generator Owner/Operator Responsibility

a. Synchronous generator owner/operators shall maintain the voltage or reactive output as specified by the control area operator.
b. When requested by SPP and NERC, the synchronous generator owner/operator shall provide (30 business days) a log that specifies the date duration, and reason for not maintaining the established voltage or reactive schedule, along with approvals for such operation received from the transmission operator. This information shall be provided on the “Generator Unit Voltage Schedule Status Report” supplied by SPP, if control area operator does not have its own form.

7.8.3 Generator Step-Up and Auxiliary Transformer Tap Settings

Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

7.8.3.1 Reporting Procedures

Control Area operators shall implement procedures concerning the reporting and changing of transformer tap settings. The procedures shall at a minimum include the following.

a. Owner/Operators shall provide current tap settings, tap setting ranges, and impedence data for all Generator Step-Up (GSU) and Auxiliary Transformers to the control area operator, SPP, and NERC upon request (30 business days). This information shall be supplied on ‘Generator Unit Transformer Tap Setting Report” supplied by SPP is control area operator does not have its own form.
b. When tap setting changes are necessary, the control area operator shall notify generator owner/operator with “Generator Unit Transformer Tap Setting Change Request” supplied by SPP, if control area operator does not have its own report. In this report, tap setting changes are specified along with a technical justification for the changes.

c. Generator Owner/Operators shall have a period of nine (9) months in which tap setting changes must be made. After setting changes have been made, Generator Owner/Operator shall supply new "Generator Unit Transformer Tap Setting Report" for the affected generating station.
d. Criteria for Generating units whose GSU and AUX transformers would be exempted.
e. List of generating units that meet exemption criteria shall be documented on "Generation Units Exempt from Tap Setting Reporting Procedures" report supplied by SPP, if Control Area Operator does not have its own form.

7.8.4 Generator Performance during Temporary Excursions

7.8.4.1 Excursions in Frequency and Voltage

Generators shall be able to sustain temporary excursions in underfrequency, overfrequency, undervoltage, and overvoltage conditions. The protective relay systems regarding these conditions shall be coordinated with SPP system underfrequency and undervoltage load shedding schemes.

SPP's underfrequency load shedding plan allows for three stages of load shed at frequencies of 59.3, 59.0, and 58.7 Hz. The members shall shed 10% of their load at each stage in an effort to stop the decline in frequency. Control Areas may elect to implement a fourth stage at 58.5 Hz which can call for the opening of tie-lines, removal of generating units from buses, additional steps of load shedding, or the breakup of the transmission system into predetermined islands with balanced amounts of generation and load in each island. Due to the structure of the underfrequency load shedding plan, it is necessary that generators be able to sustain frequencies to at least 58.5 Hz so that the load shedding plan works as designed. Any generator that must trip off line prior to system frequency declining to 58.5 Hz must have a block of load equal to the generator's output capability tripped at the same frequency as the generating unit.

In the absence of a regional or control area undervoltage load shedding plan, generators shall be able to sustain non-interruptible operation at voltages between 92% and 105% of the nominal transmission voltage at the generator bus. During Emergency and/or transient system conditions, all reasonable measures should be taken to avoid tripping of the generator due to high or low voltage.

7.8.4.2 Excursions in Real and Reactive Power Output

Generators shall be able to sustain temporary excursions in real and reactive power output that may occur during a period of declining frequency or voltage. For this reason, all generator governors and automatic voltage regulators shall be kept in automatic mode as much as practical. A generator shall not trip during stable power swings except when that particular generator is out of step with the remainder of the system.

Generators shall be able to run at maximum rated reactive and real output according to each unit's Capability Curves during emergency conditions for as long as acceptable frequency and voltages allow the generator to continue to operate.

7.8.4.3 Exempt Generators

Generators shall be exempt from this section if they meet the following criteria

a. Generator output less than 20MW
b. Generation is of intermittent variety (wind generation)

7.8.5 Generator Voltage Regulator Controls and Limit Functions

Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short term duration capabilities and protective relays.

7.8.5.1 Reporting Procedures

Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with information that ensures generator controls coordinate with the generator short term duration capabilities and protective relays. The information shall be supplied on the "Voltage Regulator Control Setting Status Report" as supplied by SPP is control area operator does not have its own form.

7.8.6 Governor Control Operation

Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency. Governors' speed regulation response shall be set such that a decrease in system frequency causes the governor to respond by increasing the generator real power output.

7.8.6.1 Reporting Procedures

a. Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with the characteristics of the generator's speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance. Information shall be supplied on "Generator Governor Characteristic Reporting" report supplied by SPP if control area operator does not have its own form.

b. Non-functioning or blocked speed/load governor controls shall be reported to control area, SPP, and NERC on request (30 business days). Information shall be supplied on "Non-Functioning Governor Control" report supplied by SPP if control area operator does not have its own form.

Southwest Power Pool, Inc.

MARKETS & OPERATIONS POLICY COMMITTEE

Report to Board of Directors

July 27, 2004

SPP CRITERIA 12 CHANGES

Background

SPP Criteria 12 concerning Electrical Facility Ratings, specifically generating equipment, has not been revised since October 2001.

Recent Activity

The net capability of generating equipment is defined within the criteria, but is not referenced to any NERC definition. The seasonal definitions within the criteria do not match those used by other SPP processes. The criteria does not address the calculation of net capability for wind plants. The GWG feels these changes need to be reflected in Criteria 12.

Conclusion

The proposed changes to Criteria 12 are shown on the attached red-line version.

Recommendation

The GWG recommends that the noted changes to Criteria 12 be approved.

Approved:	Generation Working Group	May 11, 2004
	Markets & Operations Policy Committee	July 14, 2004
Action Requested:	Approve recommendation.	

12.0 ELECTRICAL FACILITY RATINGS

12.1 Rating of Generating Equipment

To provide a basis for comparing operating margin of various entities and to assure reasonable distribution of the margin, generating equipment shall be uniformly and consistently rated to permit accurate planning. Procedures are herein established for rating generating units and establishing a system of records so that changes in capacity during the life of the equipment can be recognized. These procedures define the framework under which the ratings are to be established while recognizing the necessity of exercising judgment in their determination. The terms defined and the ratings established pursuant to these procedures shall be used for SPP purposes, including determining capacity margins for both planning and operating purposes, scheduling maintenance, and preparation of reports of other information for industry organizations, news media, and governmental agencies. These ratings are not intended to restrict daily operating practices associated with SPP operating reserve sharing, for which more dynamic ratings may be necessary. Each member shall test its generating equipment in accordance with the procedures contained herein. On the basis of these tests summer and winter net capability ratings for each generating unit and station on the member's electric system shall be established. This net capability is referenced in many NERC documents as net dependable capacity, that is the maximum capacity a unit can sustain over a specified period modified for seasonal limitations and reduced by the capacity required for station service or auxiliaries. The summer net capability of each unit may be used as the winter net capability without further testing, at the option of the member. As a minimum, each member shall conduct tests on all its generating equipment which is designated as a part of the resource for supplying its own peak load and minimum capacity margin requirement of this Criteria. The seasonal net capabilities shall be furnished to SPP for all existing generating units and upon installation of new generating units and shall be revised at other times when necessary. Members shall annually report the seasonal net generating unit capability in conjunction with the Department of Energy 411 Report data gathering effort.

12.1.1 Capability Test

Capability Tests are required to demonstrate the claimed capability of all generating units, excluding run-of-the-river hydroelectric plants and wind plants. During a Capability Test, a unit shall generate its rated net capability for a specified Test Period following a specified Settling Period. The length of these periods is determined by the type and size of unit. The unit will be within 5% of its rated capability throughout the Settling Period. Only minor changes in unit controls shall be made during this time as required to bring the unit into normal, steady-state operation. The following table specifies the duration of these periods. The reduced duration tests on the specified unit types are generally considered to be a fair and practical demonstration of unit capability. If operating experience for a given unit suggests otherwise, the system shall use this experience in establishing the time periods or use the periods in the table associated with large steam units.

Unit Type	Settling Period	Test Period
Steam > 100 MW net	2.0 hours	2.0 hours
Steam < 100 MW net	1.0 hour	1.0 hour
All other units	0.0 hour	1.0 hour

12.1.2 Operational Test

An Operational Test is used to demonstrate the ability of a generating unit to be loaded to its nominal rating. Operational tests shall be conducted at a minimum of 90% of claimed summer capability for a minimum of 1 hour. Any normal operating hour with the unit at or above 90% of claimed capability may be deemed an Operational Test.

12.1.3 Frequency of Testing

Summer Capability Tests shall be conducted once every 3 years. If the winter capability rating is greater than summer, winter tests shall also be conducted once every 3 years. Operational Tests shall be conducted once every year during the summer season. New units or units undergoing a physical or operational modification which could impact capability shall be given a capability test.

12.1.4 Rating and Testing Conditions

Ambient conditions at the time of running capability tests shall be recorded so that appropriate adjustments can be made when establishing seasonal capabilities. Conditions to be recorded are: dry-bulb temperature, wet-bulb temperature, barometric pressure, and condenser cooling water inlet temperature. Summer Capability Tests are to be conducted at an ambient temperature within 10 degrees Fahrenheit of Rating dry-bulb temperature.

Winter Capability Tests are to be conducted at an ambient temperature equal to or greater than the minimum dry-bulb temperature for winter testing and rating defined in paragraph 2.3.5.2.g.

12.1.5 Procedures For Establishing Capability Ratings

12.1.5.1 External Factors

a. Units dependent upon common systems which can restrict total output shall be tested simultaneously.

b. When the total output of a member's system is reduced due to restrictions placed upon the output of individual generating units through the operation of the Clean Air Act, or similar legislation, then the total of the individual unit ratings of a member's generating resources shall not exceed the modified system capacity.

c. The fuel used during testing shall be the general type expected to be used during peak load conditions or adjustments made to test data if an alternate fuel is used.

d. Net Capability is the net power output which can be obtained for the period specified on a seasonally adjusted basis with all equipment in service under average conditions of operation and with the equipment in an average state of maintenance. Deductions from net capability shall not be made for equipment temporarily out of service for normal maintenance or repairs.

e. The seasonal net capability shall be determined separately for each generating unit in a power plant where the input to the prime mover of the unit is independent of the others, except that in the event multiple unit plant capability is limited by fuel limitations, transmission limitations or other auxiliary devices or equipment, each unit shall be assigned a rating by apportioning the combined capability among the units. The seasonal net capability shall be determined as a group for common header sections of steam plants or multiple unit hydro plants, and each unit shall be assigned a rating by apportioning the combined capability among the units.

12.1.5.2 Seasonality

a. The summer season is defined by the months June, July, August and September. The winter season is defined by the months December, January, ~~and~~ February, and March. The adjustments required to develop seasonal net capabilities are intended to include seasonal variations in ambient temperature, condenser cooling water temperature and availability, fuel changes, quality and availability, steam heating loads, reservoir levels, ~~and~~ scheduled reservoir discharge, and wind speed.

b. The total seasonal net capability rating shall be that available regularly to satisfy the daily load patterns of the member and shall be available for a minimum of four continuous hours taking into account possible fuel curtailments and thermal limits.

c. The seasonal net capability of each generating unit shall be based upon a set of conditions, referred to as the "Rating Conditions" for that unit. This set of conditions is determined by the geographical location of the unit, and is composed of three or four factors, depending upon the type of unit. The three factors which can affect most generating units are: Ambient dry-bulb temperature, Ambient wet-bulb temperature and Barometric pressure. Condensing steam turbines which obtain condenser cooling water from a lake, river, or comparable source have a fourth factor: Condenser cooling water source temperature.

d. The Rating dry-bulb and wet-bulb temperatures shall be obtained from weather data provided in the most recently published American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) Fundamentals Handbook. The handbook is published every four years; 1989, 1993, etc., and is based on 15 years of historical weather data where available. If the generating station is within 30 miles of the nearest weather station reported in the handbook, then these temperatures will be those for the nearest station. For all other stations, rating temperatures shall be determined by interpolating between weather stations using plant latitude and longitude. Selected pages of the "Weather Data" chapter of the handbook are reprinted in the Appendix with permission of ASHRAE. The steps to be used for interpolating weather data and correcting for elevation are also presented in the Appendix.

e. If experience for a given unit suggests otherwise, members may optionally use their own site specific temperature data if accurate hourly data is available to allow calculation of the temperature levels as defined in the Criteria. Site specific data shall contain both dry-bulb and wet-bulb temperatures.

f. The dry-bulb temperature for summer rating of equipment shall be taken as that which is equaled or exceeded 1% of the total hours during the months of June through September for the plant's geographical location. The wet-bulb temperature for the summer rating shall be the "mean coincident wet-bulb" temperature corresponding to the above dry-bulb temperature. These two temperatures are listed together under the "1%"

heading in the weather data table in the Appendix.

g. The minimum dry-bulb temperature for winter testing and rating shall be taken as that which is equaled or exceeded 99% of the total hours during the months of December through March~~February~~ for the plant's geographical location. The wet-bulb temperature is not significant for the winter rating and can be disregarded. The winter dry-bulb temperature is listed under the "99%" heading in the weather data table in the Appendix.

h. Standard barometric pressure for a plant site shall be determined for each plant elevation by linearly interpolating the pressure table provided in the Appendix.

i. For those units using a lake or river as a source of condenser cooling water, the summer standard inlet temperature is the highest water inlet temperature during the hottest month of the year, averaged over the past ten years.

j. Ambient wet-bulb temperature and condenser cooling water temperature are generally not significant factors in adjusting cold weather capability of generating units. Shall special situations arise in which these temperatures are required, reasonable estimates for temperatures occurring coincidentally with the winter rating dry-bulb temperature as defined in the Criteria shall be used.

12.1.5.3 Rating Adjustments

a. The rated net capability of a unit may be above or below the actual tested net generation as a result of adjustments for Rating Conditions, with the exception of units with winter season ratings greater than their summer rating. For these units, the winter season rated net capability shall be no greater than the actual tested net generation. No rating adjustment for ambient conditions shall be made.

b. Seasonal net capability shall not be reduced to provide regulating margin or spinning reserve. It shall reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period.

c. Extended capability of a unit or plant obtained through bypassing of feed-water heaters, by utilizing other than normal steam conditions, by abnormal operation of auxiliaries in steam plants, or by abnormal operation of combustion turbines or diesel units may be included in the seasonal net capability if the following conditions are met; a) the extended capability based on such conditions shall be available for a period of not less than four continuous hours when needed and meets the other restrictions, and b) appropriate procedures have been established so that this capability shall be available promptly when requested by the system operator.

d. The seasonal net capability established for nuclear units shall be determined taking into consideration the fuel management program and any restrictions imposed by governmental agencies.

e. The seasonal net capability established for hydro electric plants, including pumped storage projects, shall be determined taking into consideration the reservoir storage program and any restrictions imposed by governmental agencies and shall be based on median hydro conditions.

f. The seasonal net capability established for run-of-the-river hydroelectric plants shall be determined using historical data on a monthly basis.

g. The net capability established for wind plants shall be determined on a monthly basis, as follows:

i. Assemble up to the most recent ten years, with a minimum of the most recent five years, of hourly net power output (MW) data, measured at the system interconnection point. Values may be calculated from wind data, if measured MW values are not yet available. Wind data correlated with a reference tower beyond fifty miles is subject to Generation Working Group approval. For calculated values, at least one year must be based on site specific wind data.

ii. Select the MW values occurring during the top 10% of load hours for the SPP region for each month (e.g., 72 hours for a typical 30 day month).

iii. Select the MW value that can be expected from the plant at least 85% of the time.

iv. A seasonal or annual net capability may be determined by selecting the appropriate monthly MW values corresponding to the host control area's peak load month of the season of interest.

v. The net capability calculation shall be updated at least once every three years.

Southwest Power Pool

Southwest Power Pool, Inc.

MARKETS & OPERATIONS POLICY COMMITTEE

Recommendations to the Board of Directors

July 27, 2004

Background and Analysis

Tariff Section 34 Revisions

At its May 6, 2004 meeting the RTWG approved modifications to SPP's Tariff at Sections 34.1 and 34.3 pertaining to the calculation of charges for network service. The original language, which was part of the Order 888 pro forma tariff, was designed to provide a mechanism for billing network service in a single transmission owner, single control area setting. The provision was designed to keep a transmission provider from over-collecting revenues from its Network customers by including the firm PTP demand in system load used for determination of the Load Ratio Share used for billing. This approach is not workable under a regional tariff utilizing a zonal pricing structure since the load impact of Firm PTP service sold under such circumstances, on each zone is not known. The RTWG has concluded that a reasonable way to accomplish the same adjustment would be to reduce the revenue requirement used in the network service charge calculation by the total Firm PTP revenue allocated to the zone for the previous calendar year and excluding the firm PTP demand from the Load Ratio Share calculation. The proposed changes to these Sections provide for this billing method change.

Tariff Section 3 Revision

At the July 1, 2004 meeting, the RTWG approved changes to Section 3 of the SPP OATT to reflect Generation Imbalance Service as an additional ancillary service offered under the SPP OATT and to obligate non-dispatchable generation connected to the Transmission System to enter into a service agreement for the provision of and payment for such service, or make alternate arrangements. Ancillary Service Schedule 4-A was approved in April for filing.

Attachment Z Revision

The MOPC considered and approved new Tariff Attachment Z at its April 14-15, 2004 meeting. Subsequently, the Board of Directors considered and approved it at its April 27, 2004 meeting. Subsequent to these approvals, in a pre-filing context, FERC Staff advised SPP to defer filing of Attachment Z, since it was their belief that the February 10, 2004 SPP RTO order precludes SPP implementation of an aggregate transmission service assessment process prior to RTO recognition. Subsequent review of the attachment by SPP's FERC counsel led to a revision of the order and wording of some of the provisions, while maintaining the same mechanisms and purposes. After extensive discussion at the July 1, 2004 meeting, the RTWG approved the proposed modification in a vote concluded on July 6, 2004.

Recommendation:

The RTWG recommends that the MOPC approve the following items:

1. The proposed modifications to Tariff Section 34

2. The proposed modification to Tariff Section 3

3. The revision of Tariff Attachment Z

Approved:	RTWG	May 6 & July 1, 2004
	MOPC	July 14, 2004

Action Requested: Approval of the MOPC recommendation

Attachment: Revised Tariff Section 34.1 & 34.3
Revised Tariff Section 3
Revisions to Proposed Attachment Z

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge for all Zones except Zone 1: Except as provided in Section 34.1a, for all network load served by the Transmission Provider, other than network load physically located within the Public Service Company of Oklahoma and Southwestern Electric Power Company, Subsidiaries of American Electric Power, Inc. Zone, the Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the difference between the Annual Transmission Revenue Requirement specified in Attachment H minus the previous calendar year's total firm Point-to-Point transmission revenue allocated to the Zone under Attachment L for each Zone in which the Network Customer's Network Load is physically located. Where a Network Customer has designated Network Load not physically interconnected with the Transmission System under Section 31.3, the Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the difference between the Annual Transmission Revenue Requirement specified in Attachment H minus the previous calendar year's total firm Point-to-Point transmission revenue allocated to the Zone under Attachment L for the Zone that is the basis for charges under Schedule 9.

34.1a Monthly Demand Charge – Zone 1: For all network load physically located within the Public Service Company of Oklahoma and Southwestern Electric Power Company, Subsidiaries of American Electric Power, Inc. Zone, the Network Customer shall pay a monthly Demand Charge calculated as shown on Addendum 1 to Attachment H.

34.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (60 minute, clock-hour); provided, however, the Network Customer's monthly Network Load will be its hourly load coincident with the monthly peak of the Zone where the Network Customer load is physically located. Where a Network Customer has Network Load in more than one Zone, the monthly Network Load will be determined separately for each Zone. Where a Network Customer has designated Network Load not physically interconnected with the Transmission System under Section 31.3, the Network Customer's monthly Network Load will be its hourly load coincident with the monthly peak of the Zone that is the basis for charges under Schedule 9.

34.3 Determination of Transmission Provider's Monthly Zone Transmission Load: The Transmission Provider's monthly Transmission System load shall be determined for each Zone on a non-coincident basis. The Transmission Provider's monthly Zone transmission load is the Zone's Monthly Transmission System Peak ~~minus the coincident peak usage of all Firm Point-To-~~

~~Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers~~.

3 Ancillary Services

As shown on Schedules 1 and 2, the Transmission Provider will provide Scheduling and Tariff Administration Service and will facilitate and arrange for the supply of Reactive Supply and Voltage Control from Generation Sources Service. In order to allow the Transmission Provider to arrange for Reactive Supply and Voltage Control from Generation Sources Service, each Transmission Owner shall maintain a schedule offering such service. All Transmission Customers are required to purchase these two services from the Transmission Provider based on the charges in Schedules 1 and 2. In addition, the Transmission Owners may continue to provide Scheduling, System Control and Dispatch Services related to transmission service under this Tariff. Each Transmission Owner must maintain a schedule showing the charges for such services. Any amounts charged the Transmission Provider by a Transmission Owner for such service shall be passed through to the Transmission Customer without mark-up. Each Transmission Owner's schedules for Scheduling, System Control and Dispatch Service and for Reactive Supply and Voltage Control from Generation Sources Service shall be available through the SPP OASIS.

Each Transmission Owner also shall maintain schedules which offer (1) Regulation and Frequency Response Service, (2) Energy Imbalance Service, (3) Operating Reserve - Spinning Reserve Service, and (4) Operating Reserve - Supplemental Reserve Service. Transmission Customers shall pay the Transmission Provider providing any of these services directly for the service. Each Transmission Owner's schedules for these services also shall be available through SPP OASIS. The Transmission Customer serving load within a Transmission Owner's(s') Control Area(s) is required to acquire these four Ancillary Services, whether from the Transmission Owner(s), from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Owner's(s') offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Owner(s). The Transmission Provider shall determine whether the Transmission Customer has adequately demonstrated that it has acquired the Ancillary Services from another source. Additionally, the Transmission Provider shall offer Generation Imbalance Service pursuant to Schedule 4-A. Every generator operating in an SPP Control Area, that is not dispatchable by such Control Area operator, shall be subject to the provisions of Generation Imbalance Service Schedule 4-A. Each generator that is subject to the provisions of this service schedule that has not made alternate arrangements with such Control Area operator shall enter into a service agreement with the Transmission Provider for Generation Imbalance Service. If the Transmission Provider determines that the Transmission Customer is taking Ancillary Services that it has not paid for from an SPP Member or otherwise has not made adequate arrangements for Ancillary Services, then the Transmission Provider may impose a penalty equal to 200% of the specific Ancillary Service charge for the host Control Area (i.e. the Control Area where the load is located) for the entire length of the reserved period but not exceeding one month. The Transmission Provider shall compensate any affected Control Areas or generators for 100% of the specific Ancillary 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.

ATTACHMENT Z

Aggregate Transmission Service Study Procedures

1. Introduction

This attachment describes the process used to evaluate long-term transmission service requests using an Aggregate Transmission Service Study process. The Transmission Provider will combine all long-term point-to-point and long-term designated network resource requests received during a specified period of time into a single ~~{Aggregate Transmission Service Study}~~ **[aggregate transmission service study]**. Using this aggregate study process, SPP will combine all requests received during an open season to conclude an optimal expansion of the transmission system that provides the necessary ATC to accommodate all such requests at the minimum total cost. ~~{The cost of transmission upgrades required to reliably provide all of the requested service will be allocated among the requests in proportion to the impacts of each request on each upgrade component}~~ **[This attachment also details cost allocation, cost recovery, and credits associated with the new facilities. For the purposes of this Attachment Z, all Transmission Owners that are not taking Network Integration Transmission Service will be treated the same as Transmission Customers taking Network Integration Transmission Service]**.

2. Open Season

The Aggregate Transmission Service Study process commences with the initiation of an open season. The open season will be 4 months in duration. During that period, customers may make requests for long-term transmission service that ~~{starts}~~

[start] no earlier than 4 months after the close of the season. Customers may submit and withdraw requests during the open season without any obligation. At the close of the open season, the Aggregate System Impact Study (ASIS) will include only queued requests for which Aggregate System Impact Study Agreements (ASISAs) have been executed. At the close of the open season, ~~{customers}~~ **[customer]** will have 15 days to execute such ASISAs per Section 19. ~~{~~

~~}~~Existing long-term firm service Customers who desire to exercise a reservation priority under Section 2.2 shall do so pursuant to the terms of Section 2.2 and shall not be included in the aggregate study.

3. Aggregate Impact Study

[a.] At the close of the Open Season, all transmission service requests subject to an ASISA will be included in the ASIS. This study shall be done in accordance with Section 19. The power flow models shall be developed for each season for the period from the earliest start of service to the latest end of service for the applicable requests. The models will include all other applicable existing reservations having equal or greater queue priority including prospective renewals of existing service having a reservation priority pursuant to Section 2.2. System constraints will be identified and appropriate upgrades determined during the ASIS. The Transmission Provider shall determine the upgrades required to reliably provide all of the requested service. SPP shall also perform a regional review of the required upgrades to determine if alternative solutions would reduce overall cost to customers. The Transmission Provider shall estimate the total cost ~~{and the allocation of such costs of these upgrades to each request impacting each~~

~~constraint in conjunction with completion of the ASIS and in accordance with Section 5 of this Attachment Z.~~

~~}~~**[of these upgrades.**

b.] SPP shall recognize constraints due to contractually limited facilities and allocate available capacity on a first come first served basis on the contractual constraint only.

~~{The cost of each component of all other upgrades in SPP shall be allocated on the basis of pro-rata MW impact described in Section 5, Cost Allocation, of this Attachment Z.~~

~~}~~**[c.]** Within the ASIS the Transmission Provider will identify the ~~{overloaded}~~ facilities limiting the availability of the requested aggregate transmission service and the upgrades required to provide this service. It will also provide an estimate of the cost of those upgrades. The assignment of upgrade costs to each reservation will be provided to enable customers to estimate their costs. Upon receipt of the Impact Study, customers will have 15 days to execute an Aggregate Facilities Study Agreement (AFSA) per Section 19.

4. Aggregate Facilities Study

The Transmission Provider shall perform an Aggregate Facilities Study including the requests of all customers who have executed an Aggregate Facilities Study Agreement (AFSA). The first phase of the facilities study process shall consist of a revision of the impact study to reflect the withdrawal of requests for which an AFSA was not executed, if any. The Aggregate Facilities Study shall be done in accordance with Section 19 of the Tariff. The Transmission Provider, in conjunction with the applicable Transmission Owners, shall determine the necessary cost and lead-time for construction of each upgrade and the estimated cost of service for each request. The Transmission Provider, in conjunction with the applicable Transmission Owners, shall determine the optimal set of solutions to reduce the overall costs for the study group and reliably provide the requested service in a timely manner.

~~{The Impact Study results shall be used to assign pro-rata MW impact allocation of upgrades to customers.}~~ [5. Cost Allocation]

~~{Pursuant to Section 7, Transmission Owner Upgrades, of this Attachment Z, Transmission Owners shall have the right of first refusal to use the cost recovery provisions of Section 8 to pay for the facilities they construct, rather than allocating such costs to customers.~~

~~After concluding the final cost allocations to each reservation in the aggregate group, the Transmission Provider shall determine the levelized monthly revenue requirement associated with the transmission service requested by each customer in the aggregate group. This levelized monthly revenue requirement is determined by calculating the present worth of the revenue requirements associated with the upgrades as}~~ **[a. For the purpose of determining the cost responsibility for each transmission service request, all upgrades required to provide transmission service for all transmission service reservations included in an Aggregate Facilities Study shall be included in an Aggregate Cost Allocation Assessment. The cost of each transmission upgrade**

component will be] allocated to each customer in the ~~{aggregate group and then assigning the appropriate monthly charge for each customer in the aggregate group for each respective reservation. For Point-to-Point Service, this charge will be compared to the charge applicable for each request under the base transmission service rates of Schedule 7, Section 1, and each customer will be required to pay the higher of the total monthly base rate charges or the monthly revenue requirement associated with the facility upgrades. For Network Integration Service this charge will be applied as a direct assignment charge pursuant to Schedule 9, Section 4 and each customer will be required to pay the monthly revenue requirement associated with the facility upgrades in addition to the total monthly base rate charges applicable under Schedule 9, Section 1.~~

~~5 Cost Allocation~~

~~For the purpose of determining the cost responsibility for each transmission service request, all upgrades required to provide transmission service for all transmission service reservations included in an Aggregate Facility Study shall be included in an Aggregate Cost Allocation Assessment.~~

~~The cost of each transmission upgrade component will be allocated to each customer in the}~~ aggregation group on a pro-rata impact basis~~{. The pro-rata allocation shall be determined by averaging the increased (positive) flow impact on the overloaded facility during the summer seasons within the term of each reservation. The cost of an upgrade will}~~ **[as provided in paragraph b. The cost of a facility upgrade shall]** be allocated to all customers in the aggregate group whose reservation period begins after ~~{or includes the}~~ commercial operation date of a facility upgrade **[(COD) or begins before the COD of a facility and extends past the COD]**. If an upgrade is <u>first</u> required during a season after completion of service, no cost would be assigned to the customer. **[With regard to the cost allocation]** ~~{6 Financial Calculation of Upgrade Costs:~~

~~First}~~, SPP shall review all upgrades and determine the earliest date that each upgrade is required. This date is considered the ~~{end of construction (EOC) date}~~ **[COD]** for each upgrade. All requests that have a positive impact on the upgrade and for which the service has not been completed prior to the ~~{EOC}~~ **[COD]** for such upgrade, shall be allocated costs for the upgrade. These requests shall be reviewed and the request that ends at the latest point in time (End of Term: EOT), shall define the amortization period for the facility**[.**

b. An allocation of the cost of each facility upgrade to each request shall be determined on a pro-rata basis for the positive incremental power flow impacts of the requested service on such upgraded facility in proportion to the total of all incremental impacts on such upgraded facility. For each upgraded facility identified, the average incremental power flow impact of each request in the aggregate study shall be determined using each summer model available for the aggregate study period, after the COD of such upgraded facility. Each impact amount shall be determined by first establishing an initial case that excludes flows associated with all requests included in the Aggregate Facilities Study. Then each request will be added to the model and the change in flow across such upgraded facility shall be determined for each request included in the Aggregate Facilities Study. The cost of an upgrade allocated to each request shall be proportional to the average positive incremental impact of each request on such facility divided by the total average positive incremental impact of all requests included in the Aggregate

Facilities Study on such upgraded facility. The cost of each upgrade shall be allocated to requests independently. Incremental flows having a negative impact on an upgraded facility shall be ignored.

c. After concluding the above cost allocations to each reservation in the aggregate group, the Transmission Provider shall determine the charges for each request by using the levelized monthly revenue requirement associated with the transmission service requested by each customer in the aggregate group. This levelized monthly revenue requirement is determined by calculating the present worth of the revenue requirements associated with the upgrades as allocated to each customer in the aggregate group and then calculating an appropriate monthly amount for each customer in the aggregate group for each respective reservation.

6. Cost Recovery:

a. For Point-to-Point Service, the levelized monthly revenue requirement derived from the cost allocation process shall be compared to the charge applicable for each request under the base transmission service rates of Schedule 7, Section 1, and each customer shall be required to pay the higher of the total monthly base rate charges or the monthly revenue requirement associated with the facility upgrades. For Network Integration Service customers the charge shall be a direct assignment charge pursuant to Schedule 9, Section 4 and each customer will be required to pay the monthly revenue requirement associated with the facility upgrades in addition to the total monthly base rate charges applicable under Schedule 9, Section 1.

Customers paying the above charges may receive credits in accordance with paragraph b of this section.

b. Any charges paid by a customer in excess of the transmission service base rate in compensation for the revenue requirements for allocated facility upgrade(s) shall be recovered by such customer from future transmission service revenues until the customer has been fully compensated. Such amount shall be recovered, with interest calculated in accordance with 18 CFR §35.19a(a)(2)(ii), from new point-to-point service that increases loading on the new facility upgrade in the direction of the initial overload. For each new point-to-point reservation having such loading impact on such new facility upgrade, made after the facility upgrade is completed (EOC date), the customer shall receive a portion of the transmission service charge equal to the positive response factor of such new reservation on the upgraded facility times the new reservation capacity times the rate applicable to such new reservation. The response factor shall be calculated on a monthly basis. This allocation from new service shall continue until the customer has been fully compensated for all charges paid in excess of the transmission service base rate.

7.] ~~{7.}~~ Transmission Owner Upgrades:

[Each] SPP Transmission ~~{Owners}~~ **[Owner]** shall ~~{each have}~~ **[possess]** the right of first refusal to obtain all rights and responsibilities afforded to customers under this Attachment Z by assuming the cost responsibility for any or all of the upgrades to their facilities or new facilities which it constructs to provide transmission service pursuant to this Attachment Z. If a Transmission Owner elects to exercise this right of first refusal, the cost of the upgrade shall not be allocated to the requests in the aggregate group. SPP shall notify each Transmission Owner of the upgrades required and provide the Transmission Owner the opportunity to exercise its right of first refusal.

8[.] ~~{Cost Recovery:~~

~~Any charges paid by a customer in excess of the transmission service base rate, in compensation for the revenue requirements for allocated upgrades shall be recovered by such customer from future transmission service revenues until the customer has been fully compensated. Such amount shall be recovered, with interest, from new service that increases loading on the new facility in the direction of the initial overload. For each new point-to-point reservation made after the facility upgrade is completed (EOC date), the customer shall receive a portion of the transmission service charge equal to the positive response factor calculated on a monthly basis. This allocation from new service shall continue until the customer has been fully compensated for all charges paid in excess of the transmission service base rate.~~

~~9}~~ Future Roll-In:

When ~~{facilities}~~ **[a facility upgrade]** being paid for pursuant to the provisions of this Attachment Z ~~{are}~~ **[is]** rolled into the revenue requirements used for the development of generally applicable transmission service rates, the ~~{amount rolled in shall be}~~ **[Transmission Owner that constructed the facility upgrade shall pay]** the remaining balance of ~~{total revenue requirements, less amounts refunded to customers less the total cost of the service pursuant to applicable base rates}~~ **[each customer's unrecovered payments described in Section 6 b that are applicable to that facility**

upgrade]. All customers and Transmission Owners~~{,}~~ who have upgraded facilities and have remaining balances subject to cost recovery pursuant to Section ~~{8}~~ **[6]**, Cost Recovery, of this Attachment Z, shall be paid in full. The customer shall continue to pay the charges specified in the customer's transmission service agreement for the transmission service initially reserved.

Southwest Power Pool

Southwest Power Pool, Inc.

FINANCE COMMITTEE

Recommendation to the Board of Directors

July 27, 2004

Funding of Cost Benefit Analysis

Background

The Southwest Power Pool Regional State Committee ("RSC") has requested $866,000 to fund unbudgeted expenditures associated with completion of a cost benefit analysis for member participation in SPP. This analysis has been deemed crucial evidence to be primarily utilized by state regulators in determining the appropriateness of their jurisdictional entities participation within the SPP.

Analysis

The Southwest Power Pool, Inc. approved 2004 operating budget totals $32.7 million. When preparing the 2004 operating budget, SPP assumed it would receive final confirmation as a RTO from the FERC by December 31, 2003 and would also fully implement its imbalance energy market in spring 2004. Delays in both of these events has allowed SPP to delay incurring numerous costs (personnel, maintenance, and consulting costs are principal among these). SPP now estimates that actual 2004 operating expenses will total $29.8 million. Inclusion of the unbudgeted costs associated with RSC activities (including $222,665 previously approved by the SPP Board of Directors) will increase the estimated 2004 operating expenditures to $30.9 million; remaining below the initial 2004 budget total of $32.7 million.

Recommendation

The Finance Committee recommends approval of the unbudgeted expenditure requested by the RSC. In discussions with representatives of the RSC the Finance Committee has requested that the RSC verify that SPP will be an owner of the cost benefit analysis report.

Approved:	Finance Committee	July 12, 2004
Action Requested:	Approve Recommendation	

IMPACT OF RSC EXPENDITURES ON SPP 2004 BUDGET

As of June 30, 3004, Southwest Power Pool is over $3.6 million under its 2004 budgeted expenses. The table below illustrates the variances from budget across the major expense categories.

Category	Budget Variance	% of YTD Budget Variance
Salaries and benefits	$ -1,279,565	-16%
Employee travel	-185,298	-43%
Administrative	-235,497	-31%
NERC Assessment	102,648	+25%
Meetings	-136,132	-52%
Communications	-223,196	-28%
Leases & maintenance	-820,470	-34%
Outside services	-827,779	-20%

In salaries and benefits, all new positions were budgeted to be filled by June 30, with the majority slated for the 1st Quarter. As of July 1, 14 of 142 authorized positions remain vacant.

The only budget category that we could project meeting or exceeding the annual budgeted amount would be in the area of Outside Services. This would be due to additional compliance filings for our RTO order and other regulatory filings done in the regular course of business.

Other budget categories are projected to incur expenses at approximately the same rate in the 2nd half of the year as in the 1st half. NERC Assessment should not be over budget at year-end since 3 of the 4 quarterly payments for 2004 have already been made and only 2 payments had been budgeted.

The following scenario assumes that the entire budgeted amount for the 2nd half of 2004 is expended in every category, with the exception of Outside Services and NERC Assessment, which are brought to their annual budgeted amounts.

Category	Original Budget	Year-End Projection
Salaries and benefits	$ 16,314,781	$ 15,035,216
Employee travel	831,345	646,047
Administrative	1,270,347	1,034,849
NERC Assessment	800,000	800,000
Meetings	507,440	371,308
Communications	1,638,072	1,414,876
Leases & maintenance	3,767,368	2,946,898
Outside services	7,573,680	7,573,680
TOTAL EXPENSES	$ 32,703,033	$ 29,822,873
Additional RSC expenses*	0	1,088,665
MODIFIED TOTAL	$ 32,703,033	$ 30,911,538

* $222,665 for budget, $866,000 for Cost Benefit Analysis

If actual expenditures during the second half of 2004 exceeds budget by 15% in every budget category, the total expenditures for 2004 would be $31.4 million.

Our budget projections indicate that including the $866,000 for the Cost Benefit Analysis in the SPP and RSC budgets (in addition to the $222,665 additional budgeted for the RSC) will not cause our total annual expenditures to exceed our current annual budgeted operating expenditures of $32.7 million.

RSC Regional State Committee
FOR THE SOUTHWEST POWER POOL

1000 Center St. Little Rock, AR 72201

July 8, 2004

Nick Brown, President and CEO
Southwest Power Pool
415 N. McKinley #800 Plaza West Bldg.
Little Rock, AR 72205-3020

Dear Nick:

Attached is the RSC's request for funding for the contract to be awarded to Tabors, Caramanis and Associates/Charles Rivers Associates to perform the cost benefit analysis for the SPP region.

Sincerely,

Denise Bode, Chairman
Oklahoma Corporation Commission

Southwest Power Pool

Southwest Power Pool, Inc.

FINANCE COMMITTEE

Report to the Board of Directors

July 27, 2004

Modification of the Budget and Funding of the Cost Benefit Analysis

Background

The Cost Benefit Task Force (CBTF) was established on April 13, 2004 and has been comprised of representatives of the Regional State Committee (RSC) and SPP membership: Sam Loudenslager (APSC), CBTF Chairman; Richard Spring (KCPL), CBTF Vice-Chairman; Jeffrey W. Price (SPP), CBTF Secretary; Michael Desselle (AEP); Shah Hossain (WR); Robin Kittle (Xcel); Mel Perkins (OGE); Dr. Ken Zimmerman (OCC); John Cita (KCC); Jess Totten (TXPUC); James Watkins (MPSC); Ricky Bittle (AECC); Darrell Gilliam (SWPA); Ryan Kind (MOPC); and Les Dillahunty (SPP). The CBTF prepared an initial Request for Proposals (RFP) that was submitted to a list of 11 potential bidders on May 14. The RFP solicited bidders' interest on one or both parts of the scope of work. Part one is intended to evaluate the costs and benefits of membership in the current structure of SPP, while Part two is designed to capture the impact of the implementation of an energy imbalance market within the SPP. The CBTF formed a small group, which reviewed the bids and selected three bidders to consider further for the cost benefit analysis (CBA). The selected bidders were invited to present their proposals in person on June 21-22. Following the interviews, it became obvious that additional clarification on the scope of effort was needed, specifically in regards to the results sought by the RSC and SPP and a better understanding of the status of SPP today. A supplement to the RFP was prepared and distributed to the selected bidders on June 25. Responses were received from the selected bidders on July 1. The bidders then participated with the CBTF in webcast presentations addressing the clarifications arising from the supplement to the RFP on July 2. The CBTF resumed discussions on July 6 and agreed through a vote of seven to three that the proposal submitted by Tabors, Caramanis and Associates/Charles Rivers Associates (TCA/CRA) should be recommended to the RSC to perform the CBA for SPP.

Analysis

The Regional State Committee Board of Directors heard and discussed the recommendation by the CBTF on July 7. The RSC adopted a Motion through a five to one vote to approve the recommendation of the CBTF to contract with TCA/CRA. The RSC then decided to recommend to the SPP Finance Committee that they approve and recommend to the SPP Board of Directors the change to the SPP and RSC budgets to include the cost of the CBA and release the funds necessary to support the CBA.

Recommendation

The Regional State Committee Board of Directors, based upon the report and action of the CBTF and a vote of the RSC members that participated on the July 7 teleconference, recommends that the SPP Board of Directors approve the changes in the SPP and RSC budgets so that the RSC can contract for the Southwest Power Pool Cost Benefit Analysis with TCA/CRA in an amount not to exceed $ 866,000.

Approved:	Regional State Committee	July 7, 2004
	SPP Finance Committee	July 12, 2004

Stipulation: The vendor contract must allow the RSC to share the cost benefit analysis report with SPP and SPP must be allowed to share the report with other parties as it chooses.

Action Requested: Approve Funding of SPP RSC Contract Award

Southwest Power Pool

Southwest Power Pool, Inc.

FINANCE COMMITTEE

Recommendation to the Board of Directors

July 27, 2004

Background

The SPP Board of Directors had directed the Finance Committee to determine the obligations of members upon withdrawal.

Analysis

The Finance Committee reviewed SPP's existing long-term obligations to determine if they should be included in the Member's Withdrawal Obligation. Additionally, the Committee looked at the practices and procedures employed by ISOs and RTOs with regard to their withdrawing members.

The Committee determined that withdrawing members should be obligated to both long-term financing agreements as well as significant long-term contractual commitments. Included would be any amounts due under financing agreements, operating leases, capital leases, consulting commitments, outsourced services, etc. The Board of Directors would be expected to review these obligations annually and communicate the obligations periodically to the membership.

The attached Exhibit A groups SPP's obligations and commitments by type and illustrates each individual member's share of the obligation were the members able to withdraw today. The Finance Committee determined that all commitments included in categories A and B would be included in calculation of withdrawal obligations.

The Committee also determined that the clause in the Membership Agreement contains ambiguity and should be modified to clarify.

Recommendation

The Finance Committee recommends the SPP Board of Directors formally acknowledge that the calculation of the withdrawal obligation for a withdrawing member will include that member's proportionate share of SPP's long-term financing obligations as defined in the membership agreement and that member's proportionate share of SPP's significant long-term contractual commitments. The specific commitments are detailed in the attached Schedule 1 as of July 27, 2004.

The Finance Committee will undertake action in the near future to modify the language to remove any perception of ambiguity.

Approved:	Finance Committee	July 12, 2004
Action Requested:	Approve Recommendation	

SPP Southwest Power Pool

SCHEDULE 1

LIST OF SPP LONG-TERM OBLIGATIONS AND LONG-TERM OPERATING COMMITMENTS

Name	Expiration
7.50% Senior Notes	March 15, 2008
4.78% Senior Notes	June 25, 2011
Bank One Revolving Credit Agreement	November 1, 2004
Plaza West Office Lease	September 30, 2011
Xerox Lease LVG251198	July 24, 2008
Xerox Lease KMM001884	July 24, 2008
Xerox Lease MWF 685166	July 24, 2008
Xerox Lease FWT006368	November 8, 2007
Xerox Lease MWL 024510	May 15, 2009
Xerox Lease MTE020754	May 15, 2009
Xerox Lease FWT006076	November 8, 2007
Accenture Consulting Services Agreement	December 31, 2006
OATI Scheduling	May 21, 2007

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July 16, 2004

Stacy Duckett, Esq.
VP, General Counsel & Corporate Secretary
Southwest Power Pool, Inc.
415 North McKinley, Suite 800
Little Rock, Arkansas 72205

Re: Determination of "Long-Term Obligations"

Dear Stacy:

You have asked our views on how Southwest Power Pool, Inc. ("SPP") might determine "long-term obligations" for purposes of setting the payment required of a withdrawing or terminated member under Section 4.2.2 of the SPP Membership Agreement. We have discussed a process under which the SPP Board of Directors would determine specific "long-term obligations" and regularly publish to the SPP members a list that would apprise them, in advance, of the obligations they might be called on to pay at the time of their withdrawal or termination. This letter addresses the Board's authority to compile such a list, and suggests criteria it might apply in doing so.

Board's Authority

SPP's Board of Directors has, under the SPP Bylaws and general principles of corporate law, both broad powers and significant discretion in managing the company's affairs. Since it is SPP's obligation under Section 4.2.2 to invoice a withdrawing or terminated member for its share of "existing obligations," SPP must, in the first instance, determine what obligations fit within that term. It is clearly within the Board's authority to set standards to be applied by SPP's officers in making that determination and, further, to specify that certain obligations or categories of obligations are to be included.

Some categories of "existing obligations" described in Section 4.2.2 are rather precisely defined but, in the case of "long-term obligations," we believe that the Board has a fair amount of discretion. In exercising that discretion, however, the Board will need to work within the framework of the definition contained in Section 4.2.2(d), which states that "long-term obligations [are] defined as amounts outstanding and payable under negotiated financing obligations, including but not limited to operating leases, capital leases, debt obligations and debt instruments."

Suggestions for Determining "Long-Term Obligations"

Because the determination of financial obligations is inherently an accounting function, we believe the Board should look to accounting principles for guidance. For example, liabilities that are classified as "long-term" on the SPP balance sheet are obvious candidates for designation by the Board as "long-term obligations" and, therefore, "existing obligations" for purposes of payments due under Section 4.2.2. SPP's December 31, 2003 balance sheet shows "long-term debt" of $20,000,000.

But we do not believe that reference to the "long-term debt" line item on the balance sheet ends the inquiry. Part of long-term debt is classified as a current liability ($5,000,000 at December 31, 2003). And there are, additionally, off-balance-sheet items, some of which (*e.g.*, operating leases) are specifically mentioned in the definition of "long-term obligations" and may be disclosed in the footnotes to SPP's financial statements (*see*, *e.g.*, Note 3 to the December 31, 2003 financial statements). Finally, we understand that SPP may have other contracts or commitments that do not appear either on the balance sheet or in footnotes to the financial statements, but that are long-term (of greater than one year's duration) in the accounting sense. All of these items we think can reasonably fit within the definition of "long-term obligations."

After an accounting analysis has been applied, the second step would be to determine whether the item in question is a "negotiated financing obligation." We are not aware that "negotiated financing obligation" is a term of art with a generally accepted definition. That, we think, gives the Board some significant degree of latitude. Where there is a party on the other side of the obligation with which SPP has "negotiated" in creating the obligation, we think the second test can be satisfied. It seems likely that most of the obligations that are candidates for "long-term obligations" under the accounting analysis would also satisfy the "negotiated" test. [A counter-example might be, say, a multi-year assessment by an improvement district on land that SPP owns. It would be hard to describe that as "negotiated"; it seems, instead to have been imposed.]

Summary

Summarizing, we think the Board can start with an accounting approach. If the item would be recorded as a long-term debt (including current portion) on SPP's balance sheet, or reflects a multi-year commitment of SPP (whether or not disclosed in the footnotes to the financial statements), it is a candidate to be designated as a "long-term obligation." If the item also can be described as "negotiated," then we believe the Board has a reasonable basis for publishing it on a list of obligations that withdrawing members must pay.

We should note that regularly publishing a list of "long-term obligations" does not preclude the addition of other items when a member actually withdraws or is terminated. Circumstances at the time may dictate that other items be included in determining what the member should pay. For example, obligations incurred since publication of the last list obviously should be examined when "existing obligations" are being tallied. And, of course, Section 8.7 of the SPP Bylaws gives the Finance Committee discretion to reduce the charge to a withdrawing or terminated member where SPP's costs can be mitigated.

The Board's designation of "long-term obligations" will carry substantial weight if challenged by a withdrawing or terminated member. That position can, we believe, be strengthened by a procedure in which the Board routinely and rationally applies the definition of "long-term obligations" to come up with a list, which it then publishes to the members. Unless there are objections voiced by the members at the time the list is published, a member who later withdraws will face an significant obstacle in trying to disavow its duty to pay its share of those obligations.

If you want to discuss this further, or talk about specific items that the Board might designate as existing obligations, please let us know.

Sincerely yours,

WRIGHT, LINDSEY & JENNINGS LLP

Walter E. May

WEM/bwk

cc: Tom Dunn

EXHIBIT A

SPP LONG TERM COMMITMENTS	Total Commitment	
Office Lease Commitment	5,245,754	
Xerox Lease Commitment	232,234	
7.50% Senior Notes (outstanding principal balance)	20,000,000	
7.50% Senior Notes (remaining interest to maturity)	3,375,000	
4.78% Senior Notes (outstanding principal balance)	25,000,000	
4.78% Senior Notes (remaining interest to maturity)	5,975,000	
TOTAL LONG-TERM FINANCING OBLIGATIONS	**59,827,988**	**A**
OATI RTO-SS	1,260,000	
Accenture COS	9,644,100	
TOTAL LONG-TERM OPERATING COMMITMENTS	**10,904,100**	**B**
MicroSoft License Agreement	105,838	
TOTAL LONG-TERM SOFTWARE LICENSES	**105,838**	**C**
SBC Select Data Circuit	11,400	
SBC Voice PRI Circuit	15,200	
AT&T Redundant Frame Relay Circuit	425,000	
MCI On-Net Agreement	600,000	
MCI Primary FRAME	440,000	
TOTAL TELECOM CONTRACTS	**1,491,600**	**D**
TOTAL COMMITMENTS	**72,329,526**	

Member	Pro Rata Share	W/D Obligation (A)	W/D Obligation (A+B)	W/D Obligation (A+B+C)	W/D Obligation (A+B+C+D)
AEP - PSO	7.9735%	4,770,397	5,639,837	5,648,276	5,767,209
AEP - SWEPCO	9.5251%	5,698,665	6,737,290	6,747,371	6,889,447
Arkansas Electric Cooperative Corporation	1.8346%	1,097,618	1,297,667	1,299,609	1,326,974
Board of Public Util.,Kansas City,KS	1.5331%	917,226	1,084,397	1,086,020	1,108,888
City Power & Light, Independence,Missouri	0.9729%	582,055	688,139	689,169	703,680
City Utilities, Springfield,Missouri	1.7440%	1,043,418	1,233,589	1,235,435	1,261,449
East Texas Electric Coop.,	0.5208%	311,604	368,396	368,948	376,716
Empire District Electric Company	2.5490%	1,525,010	1,802,954	1,805,652	1,843,673
Grand River Dam Authority	2.0992%	1,255,939	1,484,843	1,487,065	1,518,377
Kansas City Power & Light Company	6.6881%	4,001,350	4,730,626	4,737,704	4,837,464
Kansas Electric Power Coop. (KEPCo)	1.2118%	724,975	857,108	858,390	876,465
Midwest Energy, Inc.	0.9469%	566,534	669,789	670,791	684,915
Northeast Texas Electric Cooperative	0.5208%	311,604	368,396	368,948	376,716
Oklahoma Gas & Electric Company	11.5748%	6,924,948	8,187,072	8,199,322	8,371,971
Oklahoma Municipal Power Authority	1.4454%	864,745	1,022,351	1,023,881	1,045,440
Southwestern Power Administration	1.8337%	1,097,060	1,297,007	1,298,948	1,326,299
Southwestern Public Service Company	10.2197%	6,114,255	7,228,624	7,239,440	7,391,878
Tex-La Electric Coop. of Texas	0.5208%	311,604	368,396	368,948	376,716
Westar Energy-(KGE&KPL)	8.7414%	5,229,787	6,182,955	6,192,207	6,322,593
Western Farmers Electric Cooperative	2.8987%	1,734,205	2,050,277	2,053,345	2,096,582
Aquila Power	0.5208%	311,604	368,396	368,948	376,716
Aquila, Inc. - MPS and STJO	3.6715%	2,196,576	2,596,918	2,600,804	2,655,568
Aquila, Inc. - WPK	1.6751%	1,002,201	1,184,859	1,186,632	1,211,618
Aquila, Inc.-STJO	0.5208%	311,604	368,396	368,948	376,716
Calpine Energy Services, L. P.	0.5208%	311,604	368,396	368,948	376,716
Cargill Alliant	0.5208%	311,604	368,396	368,948	376,716
Central Louisiana Electric Company, Inc.	4.5572%	2,726,476	3,223,396	3,228,219	3,296,195
City of Clarksdale, Mississippi	0.5947%	355,819	420,670	421,299	430,170
City of Lafayette, Louisiana	1.2820%	766,968	906,754	908,111	927,232
Louisiana Energy & Power Authoriyt	0.9744%	582,957	689,205	690,236	704,770
Sunflower Electric Power Corp.	1.4261%	853,210	1,008,714	1,010,224	1,031,495
Entergy Services, Inc.	0.5208%	311,604	368,396	368,948	376,716
Exelon Power Team	0.5208%	311,604	368,396	368,948	376,716
Public Service Company of Yazoo City, MS	0.5688%	340,305	402,328	402,930	411,415
InterGen Services, Inc.	0.5208%	311,604	368,396	368,948	376,716

SPP LONG TERM COMMITMENTS	Total Commitment	
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Xerox Lease Commitment	232,234	
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MCI On-Net Agreement	600,000	
MCI Primary FRAME	440,000	
TOTAL TELECOM CONTRACTS	**1,491,600**	**D**
TOTAL COMMITMENTS	**72,329,526**	

Member	Pro Rata Share	W/D Obligation (A)	W/D Obligation (A+B)	W/D Obligation (A+B+C)	W/D Obligation (A+B+C+D)
Tenaska Power Services Company	0.5208%	311,604	368,396	368,948	376,716
Cinergy Corporation	0.5208%	311,604	368,396	368,948	376,716
Constellation Power Source	0.5208%	311,604	368,396	368,948	376,716
Coral Power, LLC	0.5208%	311,604	368,396	368,948	376,716
Duke Energy Trading & Marketing	0.5208%	311,604	368,396	368,948	376,716
Dynegy Marketing & Trade	0.5208%	311,604	368,396	368,948	376,716
Edison Mission Marketing & Trading, Inc.	0.5208%	311,604	368,396	368,948	376,716
El Paso Merchant Energy, LP	0.5208%	311,604	368,396	368,948	376,716
Mirant Americas Energy Marketing, L.P.	0.5208%	311,604	368,396	368,948	376,716
NRG Power Marketing, Inc.	0.5208%	311,604	368,396	368,948	376,716
TXU Energy Trading Company	0.5208%	311,604	368,396	368,948	376,716
Williams Energy Marketing & Trading Company	0.5208%	311,604	368,396	368,948	376,716
	1.0000	59,827,988	70,732,088	70,837,926	72,329,526

Southwest Power Pool

Southwest Power Pool, Inc.

HUMAN RESOURCES COMMITTEE

Report to the Board of Directors

July 27, 2004

Human Resources Committee Scope

Background

The Board of Directors of Southwest Power Pool, Inc. established a Human Resources Committee in its draft bylaws submitted with SPP's RTO application to the FERC. The duties of the Human Resources Committee are summarized in the draft bylaws. A more specific scope document will detail the responsibilities and authorities of the committee.

Analysis

The Human Resources Committee (and its predecessor the Employee Benefits Working Group) has met several times dating back to mid-2003 to document its activities in a scope document. This scope document was being developed to support the existence of a Human Resources Committee, which is intended to replace the functions of the Employee Benefits Working Group.

Recommendation

The Human Resources Committee recommends the SPP Board of Directors accept the Human Resources Committee Scope Statement as the charter of the Human Resources Committee, and approve the detailed responsibilities and authorities of the Human Resources Committee.

Approved:	Human Resources Committee	April 27, 2004
Action Requested:	Approve Recommendation	

Southwest Power Pool

Southwest Power Pool

HUMAN RESOURCES COMMITTEE

Organizational Group Scope Statement

July 27, 2004

Purpose

The purpose of the Human Resources Committee is to develop, advocate and maintain for the Board of Directors personnel policies and structures that proactively support the employees of SPP in fulfilling their responsibilities.

Scope of Activities

The Human Resources Committee will have broad responsibilities for approving organizational structure including continuous realignment to support timely execution of the SPP Strategic Plan; recruitment and employment policies; compensation and incentive policies; development and training policies; benefits including insurance, health and retirement plans; and systems for evaluating individual and organizational performance. The Human Resources Committee responsibilities include performing the tasks enumerated herein and advocating changes to the Board of Directors for their approval. The Human Resources Committee will recommend policy, structural and budgetary changes to the Board of Directors for approval. Procedural changes within established policy will be developed in consultation with the SPP staff for improved policy execution. Hiring and managing consulting expertise, actuarial assistance, investment managers, and other expert assistance in the performance of the Committee functions shall be within the purview of the Human Resources Committee unless Board approval is required for budgetary authorization. The results of evaluative processes completed by the Committee as part of their enumerated tasks below will be reported to the Board of Directors at the next subsequent Board meeting. Specific tasks include:

a. Develop, review and monitor organizational manpower plans and structure to ensure continuous alignment with the SPP Strategic Plan.

b. Review and approve employee compensation plans to ensure high employee satisfaction and desirable turnover rates.

c. Develop and maintain executive compensation plans designed to attract and retain distinguished leaders who proactively innovate to satisfy Board expectations.

d. Review and approve employee and executive benefit, health care and retirement plans. Maintain plans that are competitive in the marketplace, responsive to the law, and provide satisfaction to beneficiaries within a cost constrained budget that effectively meets stakeholder needs. Appoint trustees to manage employee benefit plans and define the rights, powers and responsibilities of trustees.

e. Establish Investment Policy Statements (“IPS”) for SPP’s defined benefit and defined contribution pension plans and review IPS annually. Review the performance of investment managers and ensure the assets are being managed in accordance with the IPS.

f. Ensure workers’ compensations programs are effectively administered.

g. Oversee SPP programs designed to maintain ethical standards and facilitate (“open door”) procedures to report violations. Ensure documentation of standards and procedures, proper functioning of programs and provision of ongoing training to all SPP employees and Board members.

h. Ensure compensation and benefit programs for Board members are responsive to individual and organizational requirements.

i. Review the structure of training and development programs within SPP and ensure execution of those plans responds appropriately to organizational needs.

j. Review and approve SPP's employee and executive performance evaluation processes.

k. Maintain a current job description for the SPP President and perform an annual job performance evaluation of the President in the third quarter of each year. Recommend compensation and benefit adjustments for the SPP President for the next fiscal year at the final Board meeting of the expiring fiscal year,

l. Perform an annual assessment of the effectiveness of the Human Resources Committee and the performance of the personnel structure within SPP; report to the Board of Directors the results and make any recommendations for change.

m. Perform such other duties as the Board of Directors may delegate or direct.

n. Hire consultants and other experts, as necessary, to advise and guide the committee in fulfilling its duties and achieving the desired workplace environment.

Representation
The Human Resources Committee shall be comprised of six members. Two representatives shall be members of the Board of Directors and one of these will be the chairperson, the other the vice chairperson. Two representative from the Transmission Owning Member sector and two representatives from the Transmission Using Member sector will be members each as nominated by the Corporate Governance Committee. The Board of Directors shall appoint the representatives of the Human Resources Committee at the regular meeting of the Board of Directors immediately following the Annual Meeting of Members. Persons designated as representatives on the Human Resources Committee will continue to serve until their successors have been appointed. When a vacancy occurs, the Corporate Governance Committee will fill the vacancy in accordance with SPP Bylaws.

Duration
The Human Resources Committee is a permanent committee. The Committee shall meet a minimum of two times per fiscal year and at other times as called by the Chair. A quorum will constitute at least half of the members of the committee but no less than three members. Proxies are allowed if reported to the Chair prior to the meeting. All meetings of the Human Resources Committee shall be open to all SPP members, members of the SPP Board of Directors, members of the Regional State Committee and invited guests unless closed by the Chair of the Committee. All meetings will be noticed in accordance with the meeting notice guidelines stated in the SPP Bylaws.

Reporting
The Human Resources Committee reports directly to the Board of Directors.

Southwest Power Pool, Inc.

STRATEGIC PLANNING COMMITTEE

Report to Membership

July 27, 2004

WAIVER OF NOTICE REQUIREMENT

Background

On July 2, 2004, the Federal Energy Regulatory Commission (the "Commission") issued an order in the SPP RTO filing docket (RT04-1) requiring additional revisions to SPP's Board and Members Committee structures. A compliance filing is required by August 2. To meet the conditions in the order, revisions to the Bylaws are necessary. Some of these revisions occur in sections that require approval of the Membership.

Analysis

Section 10.0 *Amendments* of the Bylaws requires a 30-day notice to the Membership for consideration of revisions to the Bylaws that require their approval. In order to meet the Commission's compliance filing deadline, revisions to the Bylaws must be approved by the Membership in fewer than 30 days.

Recommendation

The Strategic Planning Committee recommends that the Membership waive the 30-day notice requirement in this instance for purposes of considering and voting on revisions to the Bylaws.

Approved:	Strategic Planning Committee	July 16, 2004
Action Requested:	Approve Recommendation	

Southwest Power Pool

Southwest Power Pool, Inc.

STRATEGIC PLANNING COMMITTEE

Report to Membership

July 27, 2004

MEMBERSHIP APPROVAL OF BOARD and MEMBERS COMMITTEE STRUCTURE CHANGES

Background

On July 2, 2004, the Federal Energy Regulatory Commission (the "Commission") issued an order in the SPP RTO filing docket (RT04-1) requiring additional revisions to SPP's Board and Members Committee structures. Specifically, SPP is directed to clarify the independence of the Board of Directors, and add two sectors to the Members Committee for the retail sector, and adjust representation on the Corporate Governance Committee accordingly.

Analysis

The Strategic Planning Committee (SPC) recommends moving forward in complying with these conditions in the order. The Commission remains clear in its requirement that SPP's Board of Directors operate in an independent manner. To that end, language has been proposed in the Bylaws verbatim from the order (Section 4.6.1).

In addition, the Members Committee would be expanded by two seats to include large and small retail customer representatives (Section 5.1.1.1). The Corporate Governance Committee representation is revised to reflect the new sectors (Section 6.6).

Pursuant to Section 10.0 of the current Bylaws, changes to Sections 4.0 and 5.0 of the Bylaws regarding the structure and authorities of the Board of Directors must be approved by the Membership.

The SPC is also recommending to the Board of Directors approval of these revisions at its July 27 meeting.

Recommendation

The Strategic Planning Committee recommends that the Membership approve changes to Sections 4.0 and 5.0 of the Bylaws to become effective upon approval.

Approved:	Strategic Planning Committee	July 16, 2004
Action Requested:	Approve Recommendation	

Southwest Power Pool, Inc.

B Y L A W S

4.0 BOARD OF DIRECTORS

4.6 Functioning of the Board of Directors

In reaching any decision and in considering the recommendations of any Organizational Group or task force, the Board of Directors shall abide by the principles in these Bylaws.

4.6.1 Meetings and Notice of Meetings

The Board of Directors shall meet at least three times per calendar year and additionally upon the call of the Chair or upon concurrence of at least four directors. At least fifteen days' written notice shall be given by the President to each director, the Members Committee, and the Regional State Committee of the date, time, place and purpose of a meeting of the Board of Directors, unless such notice is waived by the Board of Directors. Telephone conference meetings may be called as appropriate by the Chair with at least one-day prior notice. Board of Directors' meetings shall include the Members Committee and a representative from the Regional State Committee (as defined in Section ~~5~~7.2) for all meetings except when in executive session; provided however, the failure of representatives of the Members Committee and/or of the Regional State Committee to attend, in whole or in part, shall not prevent the Board of Directors from convening and conducting business, and taking binding votes. The Chair shall grant any Member's request to address the Board of Directors.

5.0 COMMITTEES ADVISING THE BOARD OF DIRECTORS

5.1 Members Committee

5.1.1 Composition and Qualifications

5.1.1.1 Composition

Provided that Membership is sufficient to accommodate these provisions, the Members Committee shall consist of up to ~~16~~ 18 persons. Four representatives shall be investor owned utilities Members; four representatives shall be cooperatives Members; two representatives shall be municipals Members (including municipal joint action agencies); three representatives shall be independent power producers/marketers Members; one representative shall be a state/federal power agencies Member; ~~and~~ two representatives shall be ~~retail/~~alternative power/public interest Members; one representative shall be a large retail customer; and one representative shall be a small retail customer. Representatives will be elected in accordance with Section 5.1.2 of these Bylaws.