Southwest Power Pool

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Nicholas Brown
Senior Vice President & Corporate Secretary

October 14, 2003

Mr. Gene Argo
Mr. David Christiano
Mr. Roland "Harry" Dawson
Mr. Michael A. Deihl
Mr. Dick Dixon
Mr. Jim Eckelberger
Mr. Michael Gildea
Ms. Trudy Harper
Mr. Quentin Jackson
Mr. John Marschewski
Mr. Tom McDaniel
Mr. Stephen Parr
Mr. Gary Roulet
Mr. Harry Skilton
Mr. Richard Spring
Mr. Al Strecker
Mr. Larry Sur
Mr. Richard Verret
Mr. Gary Voigt
Mr. Walt Yeager

Hello!

Enclosed is the agenda and background materials for our upcoming SPP Board of Directors Meeting and Annual Meeting of Members on October 28 and 29, 2003 at the Peabody Hotel, Little Rock, Arkansas.

As always, please call with any questions or comments. I look forward to seeing you all again!

Take Care,

Nick

NAB:cr
Enclosure
cc: SPP Membership (via email)

Southwest Power Pool
BOARD OF DIRECTORS MEETING & ANNUAL MEETING OF MEMBERS
2003 Fall Meetings – Peabody Hotel – Little Rock, Arkansas

- A G E N D A S -

TUESDAY, OCTOBER 28

1:00 p.m. – Board of Directors Meeting

1. Administrative Items.. Mr. Al Strecker
2. Operations Policy Committee Report .... Mr. Mel Perkins
3. Strategic Planning Committee Report .... Mr. Richard Spring
4. Employee Benefits Working Group Report............................... Mr. Jim Eckelberger
5. Finance Working Group Report – 2004 Administrative Budget ...... Mr. Harry Skilton
6. Executive Session

6:00 p.m. – Reception
7:00 p.m. – Dinner & Leadership Celebration for Mr. John Marschewski

WEDNESDAY, OCTOBER 29

7:30 a.m. – Continental Breakfast
8:30 a.m. – Annual Meeting of Members

1. Administrative Items.. Mr. Al Strecker
2. President's Report .... Mr. John Marschewski
3. 2003 Organizational Overview / 2004 Outlook ....Mr. Nick Brown
4. 2003 Operational Overview / 2004 Outlook..................................... Mr. Carl Monroe
5. 2003 Financial Overview / 2004 Outlook..Mr. Tom Dunn
6. NERC Board of Trustees Report.. Mr. John Marschewski
7. Nominating Task Force Report ....Mr. David Christiano

11:00 a.m. – Board of Directors Meeting

1. Nominating Task Force..Mr. David Christiano

Noon – Adjournment

MINUTES NO. 86

Southwest Power Pool
BOARD OF DIRECTORS MEETING
Embassy Suites – Kansas City Airport – Kansas City, MO
August 26, 2003

TUESDAY

Agenda Item 1 - Administrative Items

SPP Chair Mr. Al Strecker called the regular meeting to order at 10:02 a.m., thanked everyone present for attending and referred to the agenda (Agenda – Attachment 1). Mr. Strecker stated that Agenda Items 3 and 5 would be combined and reports given later in the meeting. Mr. Strecker then called for a round of introductions. The following Board members were in attendance or represented by proxy:

Mr. Gene Argo, Midwest Energy,
Mr. Gary Voigt, Arkansas Electric Cooperative Corp.,
Mr. David Christiano, City Utilities of Springfield, MO,
Mr. Harry Dawson, Oklahoma Municipal Power Authority
Mr. Mr. Michael Desselle, proxy for Richard Verret, American Electric Power,
Mr. Michael Deihl, Southwestern Power Admin.,
Mr. Dick Dixon, Westar Energy,
Mr. Jim Eckelberger, independent director,
Ms. Trudy Harper, Tenaska Power Services Company,
Mr. Stephen Parr, Kansas Electric Power Coop.,
Mr. John Marschewski, Southwest Power Pool,
Mr. Tom McDaniel, independent director, via teleconference
Mr. Gary Roulet, Western Farmers Electric Cooperative,
Mr. Harry Skilton, independent director,
Mr. Richard Spring, Kansas City Power & Light,
Mr. Al Strecker, OG+E,
Mr. Larry Sur, independent director, via teleconference

There were 54 persons in attendance representing 22 members (Attendance List - Attachment 2). One proxy statement was received by the Secretary (Proxy - Attachment 3).

Mr. Strecker referred to draft minutes of the June 24, 2003 Meeting (6/24/03 Meeting Minutes - Attachment 4) and asked for necessary corrections or a motion for approval. Mr. Dawson motioned that the minutes be approved as distributed. Mr. Skilton seconded this motion, which passed unopposed.

Agenda Item 2 – Nominating Task Force Report

Mr. Strecker asked Mr. Christiano to give the Nominating Task Force Report. Mr. Christiano referred to the Nominating Task Force Report (Nominating Task Force Report – Attachment 5). Mr. Christiano stated that the departure of J. M. Shafer, Western Farmers, left a vacant transmission owner seat on the Board of Directors as well as a vacant vice chair position. Mr. Christiano stated that the Nominating Task Force and Chair of the Board of Directors are responsible for submitting a nomination and as such nominates to the Board of Directors Gary Roulet to fill the vacant transmission owner seat on an interim basis until the next meeting of members, and Jim Eckelberger for vice chair. Hearing no other nominations, the Board of Directors elected Gary Roulet to serve on the Board of Directors on an interim basis and elected Jim Eckelberger as vice chair of the Board of Directors.

Agenda Item 3 – Strategic Planning Committee Report

Mr. Strecker then asked Mr. Spring to present the Strategic Planning Committee (SPC) Report. Mr. Spring referred to the SPC Report and Recommendations to the Board of Directors (SPC Report & Recommendations– Attachment 6), gave a brief background and updated the Board of Directors on the work of the SPC resulting in this report and recommendations along with the supporting draft documents (SPC Slides – Attachment 7). Mr. Spring then presented the SPC recommendations to the Board of Directors as follows:

- Recommendation 1: Approve the attached modifications to the SPP Bylaws and Membership Agreement (including the attachment providing a form of an agreement for independent transmission company participation) for filing with FERC in an application for recognition as a regional transmission organization. The documents are to become effective on the first day of the calendar month occurring between the 30th day and 60th day following a final FERC order recognizing SPP as a regional transmission organization.

- Recommendation 2: Authorize the Staff to file an application with FERC as soon as practicable seeking SPP recognition as a regional transmission organization pursuant to FERC Order 2000, and to make necessary corrections and formatting changes to the governing documents subject to review of the SPC.

- Recommendation 3: Approve a transition to the new governance structure by which SPP's non-stakeholder Directors become the Board of Directors and the stakeholder Directors become the Members Committee, all carrying forward their current terms.
- Recommendation 4: Accept the attached form of a seams agreement for inclusion in the FERC filing, and authorize the SPP Staff to immediately begin negotiations with neighboring entities on specific agreements pursuant to this form.

After the recommendations were presented, Mr. Eckelberger referred to the Bylaws Section 3.13.2 and suggested a change from "6" to "7" persons. He then referred to the Membership Agreement Section 4.2.2 (b) and suggested changing the word "paid" to "incurred".

Chairman Hochstetter of the Arkansas Public Service Commission proposed that the Regional State Committee (RSC) Section 5.0 of the Bylaws be held pending further language being submitted by the states.

Following addition discussion, Mr. Dixon motioned that the Board of Directors approve the four Recommendations (including the proposed changes below) of the SPC except section 5.2 of the SPP Bylaws (and any additional related sections for Bylaws and Membership Agreement needed for State jurisdictional issues) and not file until these issues are resolved or 9/30/03 whichever is earlier.

- Section 3.13.2 Bylaws from "6" to "7" persons.
- Section 4.2.2 b Membership Agreement change "paid" to "incurred"
- SPP Board directs the SPC to work with the states and FERC to resolve section 5.2 of the Bylaws and related proposed additional sections.

Mr. Christiano seconded this motion which passed with one vote in opposition (Mr. Dawson).

Agenda Item 4 – Operations Report

Mr. Strecker then asked Mr. Monroe to give the Operations Report. Mr. Monroe presented slides reviewing the 2003 Operational Highlights as well as slides documenting the events of August 14, 2003 (Operations Report – Attachment 8).

Agenda Item 3 & 5 – Finance Working Group Report and Tariff Fee Recommendation

Mr. Strecker then asked Mr. Skilton and Mr. Dunn to give the Finance Working Group Report (Tables – Attachment 9). Mr. Dunn referred to the Staff report and recommendation on Assessment and Tariff Schedule 1 Rates (Staff Report – Attachment 10). After some discussion, it was determined that no vote would be taken on the recommendation at this time.

Adjournment
The Board of Directors will meet via teleconference on September 22, 2003 at 2:00 p.m. CDT to discuss the Tariff Fee Recommendation from the Finance Working Group and the RSC proposed language for the Bylaws.

The Board of Directors agreed to a meeting on Tuesday, October 28 (1:00 p.m. – 5:00 p.m.) and the Annual Meeting of Members on October 29, 2003 (8:00 a.m. – noon) in Little Rock, AR.

Mr. Strecker thanked everyone for their participation and at 1:10 p.m. excused all non-board members from the room in order for the Board of Directors to continue in Executive Session.

Nicholas A. Brown, Corporate Secretary

Southwest Power Pool
BOARD OF DIRECTORS TELECONFERENCE MEETING
September 22, 2003
2:00 p.m. CDT

- Summary of Action Items -

1. Approved minutes of the August 26, 2003 meeting with one correction.

2. Approved the recommended rosters for the Market Working Group and the Business Practices Working Group.

3. Approved an assessment and tariff Schedule 1 rate of $0.15/MWh effective October 1, 2003.

4. Approved modifications to the implementation plan for the energy imbalance market.

5. Approved the continuation of “special conditions” for Southwestern Power Administration (SWPA) through October 31, 2004 to the extent that SWPA maintains its membership in SPP.

MINUTES NO. 87

Southwest Power Pool
BOARD OF DIRECTORS TELECONFERENCE MEETING
September 22, 2003
2:00 p.m. CDT

Agenda Item 1 - Administrative Items

SPP Chair Mr. Al Strecker called the teleconference meeting to order at 2:04 p.m., thanked everyone present for attending and referred to the agenda (Agenda – Attachment 1). A quorum was declared with the following Board members in attendance or represented by proxy (Proxy – Attachment 2):

Mr. David Christiano, City Utilities of Springfield, MO,
Mr. Harry Dawson, Oklahoma Municipal Power Authority
Mr. Michael Desselle proxy for Mr. Mr. Richard Verret, American Electric Power,
Mr. Michael Deihl, Southwestern Power Admin.,
Mr. Dick Dixon, Westar Energy,
Mr. Jim Eckelberger, independent director
Ms. Trudy Harper, Tenaska Power Services Company,
Mr. Mike Gildea, Duke Energy
Mr. Stephen Parr, Kansas Electric Power Coop.,
Mr. John Marschewski, Southwest Power Pool,
Mr. Gary Roulet, Western Farmers Electric Cooperative,
Mr. Harry Skilton, independent director,
Mr. Richard Spring, Kansas City Power & Light,
Mr. Al Strecker, OG+E,
Mr. Larry Sur, independent director
Mr. Gary Voigt, Arkansas Electric Cooperative Corp.,
Mr. Walt Yeager, Cinergy Services

SPP Staff included Nick Brown, Carl Monroe, Tom Dunn and Stacy Duckett. Guests participating included Ricky Bittle (AECC), Mel Perkins (OG+E), Carl Huslig (Aquila), Bary Warren, Mike Palmer and Rick McCord (EDE), Tom Stuchlick (Westar), Randy Bynum, Richard House and Sam Loudenslager (APSC), Larry Holloway and Cynthia Claus (KCC), and Linda Gutherie and Kelli Leaf (OCC).

Mr. Strecker referred to draft minutes of the August 26, 2003 Meeting (6/26/03 Meeting Minutes - Attachment 3) and asked for necessary corrections or a motion for approval. Mr. Quentin Jackson attended the August 26, 2003 Board of Directors meeting, but was omitted from the minutes. Mr. Dawson moved that the minutes be approved as modified. Mr. Skilton seconded this motion, which passed unopposed.

Agenda Item 2 – Market Working Group and Business Practices Working Group Report

Mr. Monroe was asked to give the Market Working Group and Business Practices working Groupreport requesting the approval of the rosters for each Group as presented (Market Working Group and Business Practices Working Group Recommendation – Attachment 4). These groups are considered critical to initiatives of SPP. After discussion and minor changes, Mr. Spring moved that the report be accepted as presented. Mr. Eckelberger seconded this motion, which passed unopposed.

Agenda Item 3 – Finance Committee Report

Mr. Skilton presented the Finance Committee report concerning assessment and Tariff Schedule 1 rates (Finance Committee Recommendation – Attachment 5). It was recommended that the SPP Board of Directors establish an assessment and tariff Schedule 1 rate of $0.15/MWh effective October 1, 2003. SPP will hold any revenue collected in excess of budgeted costs to fund, at the direction of the Finance Working Group, repayment of prior member overpayments resulting from shortfalls in administrative fee revenue under the regional tariff and/or repayment of the $5 million required principal payment due March 2004. During discussion it was decided to replace “at the direction of the Finance Working Group” with "subject to approval of the Board of Directors". Mr. Skilton moved to approve this recommendation as modified. Mr. Spring seconded the motion, which passed unopposed.

Agenda Item 4 – Strategic Planning Committee Reports
Mr. Spring presented recommendations from the Strategic Planning Committee (SPC) (MWG Recommendation– Attachment 6 and SWPA Recommendation– Attachment 7).

Mr. Spring submitted the SPC recommendation from the Market Working Group (MWG) requesting approval of a slight modification to the implementation plan for the energy imbalance market. Mr. Spring moved to approve this recommendation. Mr. Marschewski seconded the motion, which passed unopposed.

Mr. Spring then submitted the SPC recommendation regarding SWPA's continued participation in SPP. It was determined that the transition of SPP into a FERC recognized regional entity is causing the Southwestern Power Administration (SWPA) to meet certain federal requirements prior to continuing their participation in SPP; therefore, the following recommendation was approved by the SPC and submitted for Board approval:

> "To the extent that Southwestern Power Administration (SWPA) maintains its membership in SPP (including its present "special conditions") through October 31, 2004, SPP staff supports and recommends to the SPP Board Of Directors an additional "special condition" to Exhibit 1 of SWPA's new Membership Agreement to continue the provisions of current SPP services including reliability coordination, OASIS administration, tariff administration, security coordination, scheduling and automated reserve sharing, while allowing SWPA to delay participation in SPP's markets. SPP will waive any additional exit cost responsibilities related to these markets through October 31, 2004. If SWPA chooses between October 31, 2003 and October 31, 2004 to participate in the market, the waiver of the additional exit cost responsibilities associated with the market will terminate."

Mr. Spring moved to approve the SWPA recommendation. Mr. Dixon seconded the motion, which passed unopposed.

It was recommended to address the subject of continuation of efforts with states at the next Board of Directors meeting.

Adjournment
The Board of Directors agreed to a teleconference meeting on Wednesday, October 1, 2003, at 1:00 p.m. CDT. Mr. Strecker thanked everyone for their participation and adjourned the teleconference at 3:00 p.m.

Nicholas A. Brown, Corporate Secretary

Southwest Power Pool
BOARD OF DIRECTORS TELECONFERENCE MEETING
October 1, 2003
1:00 p.m. CDT

- Summary of Action Items -

1. Approved the recommendation of the Strategic Planning Committee related to language for the SPP Bylaws regarding a Regional State Committee.

MINUTES NO. 88

Southwest Power Pool
BOARD OF DIRECTORS TELECONFERENCE MEETING
October 1, 2003
1:00 p.m. CDT

Agenda Item 1 - Administrative Items

SPP Chair Mr. Al Strecker called the teleconference meeting to order at 1:04 p.m., and thanked everyone present for attending. A quorum was declared with the following Board members in attendance or represented by proxy:

Mr. David Christiano, City Utilities of Springfield, MO,
Mr. Harry Dawson, Oklahoma Municipal Power Authority,
Mr. Michael Desselle proxy for Mr. Mr. Richard Verret, American Electric Power,
Mr. Michael Deihl, Southwestern Power Admin.,
Mr. Dick Dixon, Westar Energy,
Mr. Jim Eckelberger, independent director
Ms. Trudy Harper, Tenaska Power Services Company, and proxy for Mike Gildea, Duke Energy,
Mr. Stephen Parr, Kansas Electric Power Coop.,
Mr. John Marschewski, Southwest Power Pool,
Mr. Gary Roulet, Western Farmers Electric Cooperative,
Mr. Harry Skilton, independent director
Mr. Richard Spring, Kansas City Power & Light,
Mr. Al Strecker, OG+E,
Mr. Larry Sur, independent director,
Mr. Walt Yeager, Cinergy Services

SPP Staff included Nick Brown, Carl Monroe, and Stacy Duckett. Guests participating included Ricky Bittle (AECC), Carl Huslig (Aquila), Bary Warren (EDE), and Commissioner Denise Bodie (OCC).

Mr. Strecker noted that the Board would defer any pending administrative items until the next meeting.

Agenda Item 2 – Strategic Planning Committee Reports

Mr. Spring presented the report from the Strategic Planning Committee (SPC) regarding the language to be included in the revised SPP Bylaws related to the role of the Regional State Committee in the organization (Attachment 1). The SPC recommended that the “general” language be approved for inclusion in the Bylaws that are to be part of SPP’s RTO filing, and that the SPC continue to work with the states on more detailed language, or in the alternative, a separate agreement between SPP and the states that would detail the relationship. The results of these efforts are to be presented at the Board of Directors meeting on October 28. Mr. Spring motioned for approval of the recommendation; Mr. Desselle seconded the motion. Considerable discussion followed. A roll call vote was taken and the motion was approved with 15 votes in favor and one abstention.

Adjournment

The Board of Directors will meet in Little Rock on Tuesday, October 28, 2003, at 1:00 p.m. CST. Mr. Strecker thanked everyone for their participation and adjourned the teleconference at 1:28 p.m.

Nicholas A. Brown, Corporate Secretary

Southwest Power Pool
OPERATIONS POLICY COMMITTEE
Recommendation to the Board of Directors
October 28, 2003

SPP CRITERIA 7 UPDATE

Background

The NERC IDWG (Interconnections Dynamics Working Group) asked the SPP SPCWG to update templates and the associated SPP criteria for which the SPCWG is responsible.

Recent Activity

At the June 10th, 2003 SPCWG meeting, the criteria was compared to the templates received from NERC and changes made to keep the criteria in compliance with NERC guidelines.

Conclusion

The changes to Criteria 7 as shown on the attachment will make it compliant with the NERC templates.

Recommendation

The SPCWG recommends that the language as shown in the attachment be incorporated into SPP Criteria 7.

Approved

System Protection and Control Working Group	June 10, 2003
Operations Policy Committee	September 30, 2003

Action Requested

The Board of Directors is requested to approve the Operations Policy Committee recommendation.

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, 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.

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 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 be waived 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 projected summer peak load. The relays shall be set to shed the thirty (30) percent total in increments of projected 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 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 7.5.3. 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.
OPERATIONS POLICY COMMITTEE
Recommendation to the Board of Directors
October 28, 2003

Background

On March 20 of this year, the SPP/MISO merger was terminated and a Strategic Planning Task Force was formed to completely review the SPP organization considering the current industry environment and to make appropriate recommendations to the Board. The Board approved its initial report on April 14th. The strategic plan included the following discussion and recommendations related to market implementation:

> The SPTF sees value, merit and benefit in SPP providing the remaining functions necessary to be in compliance with FERC Order 2000. As described above, SPP has been providing independent regional security coordination transmission administration for a number of years. The remaining functions necessary for SPP compliance with Order 2000 include adding an imbalance energy market, and some form of market-based congestion management. Current processes and procedures related to imbalance energy accounting and transmission congestion management are neither effective nor efficient. Implementation of some form of real-time energy balancing market would provide incentive for proper behavior and would enable SPP members to more equitably settle imbalance energy. SPP's current method of managing transmission congestion ignores the differing value of transactions that are curtailed to provide system relief and is therefore very inefficient. Also, while regionalization has greatly standardized the provision of certain services, regional differences do continue to exist and more work remains on managing seams with existing and forming regional neighbors. Therefore, the SPTF recommends the following evolutionary steps related to Order 2000 compliance.
>
> 1. SPP should evaluate with the states options for and a phased implementation of a real-time balancing market.
> 2. SPP should evaluate with the states options for and a phased implementation of market monitoring.
> 3. SPP should evaluate with the states options for and a phased implementation of market-based congestion management.
>
>   *(These actions should be assigned to the combination of the Market Settlement Working Group and the Congestion Management Working Group with a target of having a detailed plan by June 1, 2003.)*
>
> 8. Provided that the previous actions are successfully implemented, SPP should seek RTO recognition by the FERC.
>
>   *(These actions should be assigned to senior staff and the SPTF with a target of having a detailed plan by June 1, 2003.)*

The implementation of these initiatives was not contingent upon RTO recognition, but rather seeking RTO recognition was contingent upon successful implementation of these initiatives. The Strategic Planning Task Force developed a Secondary Report, which was approved by the Board of Directors on June 24, 2003. This secondary report contained the following recommendation related to market implementation:

Initial Recommendation: *SPP should evaluate with the states options for and a phased implementation of a real-time balancing market, market monitoring, and market-based congestion management.*

These actions were assigned to the combination of the Market Settlement Working Group and the Congestion Management Working Group (the Market Working Group). The Group met several times and provided a recommended plan to the SPTF that was accepted on May 28. The detailed plan is provided as Attachment #1.

Summary of the plan: The plan is to be implemented in three phases: Phase 1 - Real-Time Balancing Market with Market Monitoring and Market Power Mitigation; Phase 2 - Market Based Congestion Management; Phase 3 - Ancillary Services Market. Implementation is to begin with the prior market system design developed by SPP during 2001, and perform a detail design for Phase I and a high-level design for the other phases. Changes in Phase I to support other phases will be incorporated with an objective of November 2004 implementation for all of Phase I. Phase 1 will be broken down into three distinct increments: a) Settlement of Imbalance at tariff filed rates of each Transmission Owner with an objective of February 2004; b) Enhanced Reliability Data and Net Schedule Interchange with an objective of April 2004; and c) Offer-based energy imbalance market resulting in the use of market-based rates for imbalance settlement with an implementation objective of November 2004. The objective for Phase 2 – Market Based Congestion Management is for implementation in November 2005 and Phase 3 – Ancillary Services Market studied for implementation in November 2006.

The implementation of each successive phase will proceed working with the state and federal regulators based on cost benefit analysis implications. Each successive phase of SPP or neighboring entity requires seams management/coordination.

The related recommendation in the approved report was:

- Accept the Market Implementation Plan as proposed by the Congestion Management Systems and Market Settlement Working Groups and the SPTF as the approach for SPP to become compliant with FERC Order 2000;

Again, this recommendation was not contingent upon RTO recognition, but rather to move into compliance with Order 2000. However, this secondary report also included the following recommendation related to RTO recognition:

Initial Recommendation: *Provided that the previous actions are successfully implemented, SPP should seek RTO recognition by the FERC.*

The SPTF discussed in its June10-11 meeting the large amount of attention given the questions of whether and when SPP should submit a filing seeking FERC recognition as an independent regional organization. Given the nature of other recommendations made as part of this strategic plan and the budgetary impacts of those recommendations, the SPTF believes that certainty of FERC recognition is needed as soon as possible, and the SPTF is recommending that it be directed to prepare necessary filing documents for Board consideration at their August 26, 2003 meeting.

The related recommendations in the approved report were:

- Accept that SPP governance affirmed at the last Board meeting does not meet the expected requirements of independence expressed by FERC and directs the SPTF to submit further governance recommendations, including bylaw changes, to the Board in August recognizing the need to maintain the current level of stakeholder input at all Board meetings. The SPTF will include active state involvement in the development of these recommendations; and
- Accept that FERC recognition as an independent regional organization is needed as soon as possible and direct the SPTF to prepare necessary filing documents for Board of Directors consideration at the August 26, 2003 meeting.

Recent Activities

The Markets Working Group, Strategic Planning Committee and Staff have been working to implement both the energy imbalance market and achieving FERC recognition as an RTO in parallel. As such, the Board of Directors approved modifications to SPP's 2003 budget at its August 26^{th} meeting necessary to carry out imbalance market elements of the strategic plans and Staff has been working with the Finance Working Group on the budget for 2004.

The MWG has met four times from July 17 to September 11 and:

1. Identified issues and documents;
2. Established several task forces;
    a. MMMPMTF,
    b. MSITF,
    c. SDMTF,
3. Identified issues needing input by other organizational groups;
    a. Regional Tariff Working Group,
    b. Operations Reliability Working Group,
4. Assigned issues to participants, and
5. Agreed on;
    a. Nodal generation,
    b. Zonal load with nodal option,
    c. LMP for imbalance (ex-ante in Phase 1, subject to review).

Analysis

After review of the parameters included in the strategic plan (the timing of the Phase 1, including each increment, and building upon the 2001 market system), the MWG concluded that contracting with Accenture for the commercial operations functions of the energy imbalance market is considered to be less costly, in the short-run, than performing the functions with SPP staff and resources. Additionally, use of SPP resources, bringing the systems in-house, programming, and testing, would delay the implementation by a minimum of 12 months. These costs are not all of the costs that are necessary to implement Phase 1 systems and will require further review and approval of expenditures. Recovery of costs from membership/participants was not addressed by the MWG, and is expected to be the responsibility of the Finance Working Group. Concerns raised during Markets Working Group discussion were that some members believe a cost benefit analysis may be necessary or appropriate and it may not be appropriate to spend funds prior to RTO approval.

Staff and the Markets Working Group engaged the full-representation Operations Policy Committee on *technical* portions of the *tactical* aspects of implementing the *strategic* direction of the Board and Strategic Planning Committee (now a permanent group). The *financial* portions of the *tactical* aspects were sent to the Finance Working Group. This is the same procedure utilized in the past on all major SPP projects, primarily due to the confidential nature of vendor proposals. The technical aspects of the project for which Operations Policy Committee support was sought were 1) the outsourcing to a vendor rather than SPP Staff support, and 2) the utilization of Accenture versus another vendor.

The Operations Policy Committee discussed this at their September 29-30, 2003 meeting and many members questioned the relationship between SPP filing for recognition from FERC and the timing for implementation of Phase 1.

Recommendation
The Operations Policy Committee recommend that the approach of the Markets Working Group in developing an implementation plan for Phase 1 is acceptable, without due consideration of the financial commitments or financial impacts. However, the Operations Policy Committee requests the Board of Directors clarify whether the timing and expenditures of Phase 1 implementation precedes or is dependent upon RTO approval.

Approved:	Market Working Group	September 11, 2003
	Operations Policy Committee	September 29, 2003

Action Requested: Approve Recommendation

OGE Energy Corp. PO Box 321
Oklahoma City, Oklahoma 73101-0321
405-553-3000
www.oge.com

October 9, 2003

Al Strecker
Chair Southwest Power Pool Board of Directors
P. O. Box 321, M/C 1106
Oklahoma City, OK 73101

Dear Mr. Strecker:

At the Southwest Power Pool Operations Policy Committee (OPC) meeting on September 29-30, 2003, the committee passed the following action item:

> *Approved the approach of the MWG in developing an implementation plan for Phase 1 is acceptable to the OPC, without due consideration of the financial commitments or financial impacts. However, the OPC requests the Board of Directors clarify whether the timing and expenditures of Phase 1 implementation precedes or is dependent upon RTO approval. The OPC directed the Chair to advise the BOD of this action for them to consider prior to October 28, 2003.*

During the discussion of this action item, several members expressed concern over the continued development of the SPP Imbalance Energy Market systems in the absence of RTO recognition. The Operations Policy Committee does approve of the Market Working Group direction but is hesitant to recommend to the board this action requiring future expenditures until the board clarifies the following important premise: Does implementation of the Market Plan Phase 1 continue to completion regardless of SPP recognition as a Regional Transmission Organization?

Sincerely,

Mel Perkins
Chair, Operations Policy Committee
Southwest Power Pool

MP/trm

Southwest Power Pool
STRATEGIC PLANNING COMMITTEE
Report to the Board of Directors
October 28, 2003

IMBALANCE ENERGY MARKET EXPENDITURES

Background

At its September 29-30, 2003 meeting, the SPP Operations Policy Committee approved the following:

> *Approved the approach of the Markets Working Group in developing an implementation plan for Phase 1 is acceptable to the Operations Policy Committee, without due consideration of the financial commitments of financial impacts. However, the Operations Policy Committee requests the Board fo Directors clarify whether the timing and expenditures of Phase 1 implementation precedes or is dependent upon RTO approval. The Operations Policy Committee directed the Chair to advise the Board of Directors of this action for them to consider prior to October 28, 2003.*

This issue was discussed by the Strategic Planning Committee in light of its recommendations contained in the Initial and Secondary Strategic Plan Reports approved by the Board of Directors on April 14 and June 24. Given the nature of SPP's RTO application filed on October 15, 2003, the Strategic Planning Committee believes that work should continue on the imbalance energy market initiative, but long-term capitol commitments should be avoided until RTO recognition for the organization is obtained from the Federal Energy Regulatory Commission.

Recommendation

The SPP Strategic Planning Committee recommends to the Board of Directors that Staff continue working with the vendors at current spending levels, members, and states in the development of the imbalance energy market systems. The Strategic Planning Committee further recommends that the Board of Directors delay execution of a vendor contract committing SPP to long-term or complete imbalance energy market systems development until Regional Transmission Organization recognition is granted.

Approved: Strategic Planning Committee October 13, 2003

Action Requested: Approve Recommendation

Southwest Power Pool
EMPLOYEE BENEFITS WORKING GROUP
Report to the Board of Directors
October 28, 2003

MERIT INCREASE

Background
SPP management recommends funding equal to 3% of total SPP staff salaries as of December 31, 2003 to be used to provide merit compensation increases to SPP staff members during 2004.

Analysis
SPP management has reviewed the current salaries of employees, the marketplace for employees in which SPP operates, merit increases proposed at several SPP member institutions and merit increases proposed by several RTO/ISO organizations in the U.S. SPP management believes increases for existing employees are required to maintain a qualified and motivated workforce to complete SPP's mission. The financial impact of a three percent merit increase for the Staff in 2004 is $258,000. In 2003 the approved merit increase was four percent.

Recommendation
The EBWG recommends the SPP Board of Directors approval of a three percent salary adjustment for SPP staff.

Approved: Employee Benefits Working Group October 13, 2003

Action Requested: Approve Recommendation

Southwest Power Pool
EMPLOYEE BENEFITS WORKING GROUP
Report to the Board of Directors
October 28, 2003

MARKET VALUE ADJUSTMENTS

Background

Specific SPP employees are performing functions that place their market value beyond their current compensation level.

Analysis

SPP management has reviewed the SPP staffing, functions and compensation levels. The results of this review have highlighted several positions, primarily in the Manager and Director levels, where SPP compensation is not highly correlated with the existing market as computed by Hewitt Associates in its 2001 Salary Survey prepared for SPP. SPP management is proposing sufficient funding in the 2004 budget, allowing management to address these market value issues on a case-by-case basis. The structural adjustments are intended to appropriately price the responsibilities inherent at the Director and Manager level and will prove invaluable as a retention tool. The financial impact of this market adjustment is $207,000.

Recommendation

The EBWG recommends the SPP Board of Directors approval of a market adjustment for certain SPP staff in the amount of $207,000.

Approved: Employee Benefits Working Group October 13, 2003

Action Requested: Approve Recommendation

Southwest Power Pool
FINANCE WORKING GROUP
Recommendation to the Board of Directors
October 28, 2003

Background

The Finance Working Group, consisting of Harry Skilton (chair), Trudy Harper, Gene Argo, Dick Dixon, Jim Eckelberger and John Marschewski met on October 7, 2003 to review SPP's proposed budget for 2004. SPP's 2004 proposed budget includes expenditures as follows:

Operating Expense, Interest Expense, Principal Repayment	$ 38,332,282
Capital Expenditures	$ 15,889,259

This budget may be further categorized as follows:

	Operating	Capital
Base Operations	$ 28,593,156	$ 3,036,804
Imbalance Energy	9,034,497	5,052,455
Market Monitoring/Mitigation	620,629	3,000,000
Congestion Management	84,000	4,800,000

SPP will be required to obtain financing sufficient to fund capital projects expected to begin during 2004. Capital project financing will total $16 million during 2004. SPP will also require working capital financing to support cash flow timing differences estimated to be between $6 million to $8 million. SPP seeks authority to renew and increase its existing revolving facility to $10 million to support temporary cash needs in 2004.

Pursuant to SPP's capital expenditure funding policy, SPP will fund capital expenditures through new borrowings. Based on the budget outlined above, SPP will need to raise $16 million in new long-term debt during 2004.

Recommendation

The Finance Working Group recommends approval of the Operating and Capital budgets as submitted.

The Finance Working Group further recommends that authority to expend funds for items identified in the budget as Imbalance Energy expenditures, Market Monitoring/ Mitigation expenditures and Congestion Management expenditures be subject to future specific approval of the SPP Board of Directors. Further, the Finance Working Group and SPP staff will negotiate with lenders to arrange suitable financing to fund 2004's capital expenditures. Specific SPP Board of Directors approval will be required prior to executing new long-term borrowing arrangements.

INTRODUCTION/OVERVIEW

SPP's 2004 gross operating budget totals $40 million, inclusive of debt service costs, as compared to $23.8 million for 2003's current estimate. Capital projects, primarily related to development and implementation of SPP's energy markets, will total nearly $16 million, with an estimated average useful life of 5.5 years. Staff costs continue as the largest single operating expense. Headcount will increase from a projected year-end 2003 total of 122 to 142 by December 2004, resulting in an increase in salary and benefit expenses to $16.3 million as compared to $12.5 million in 2003.

SPP's 2004 budget represents a substantial departure from prior SPP budgets, both in terms of magnitude and structure. SPP will segregate its capital budget from the operating budget. Capital projects will be funded through borrowing arrangements with commercial bank and institutional lenders. SPP's total cash outflows are expected to exceed $55 million during the year as SPP works toward achieving the initiatives developed by the Strategic Planning Committee and approved by the Board of Directors.

The Boards of both organizations in March 2003 mutually terminated the merger of SPP and Midwest ISO. Following merger termination, SPP formed a Strategic Planning Committee (SPC) to develop a long-range strategic plan for the Company and to begin moving SPP towards the resulting long-range goals. Several strategic initiatives were developed by the SPC and approved by the Board. Paramount among these was 1) development and implementation of an energy market within the SPP footprint; 2) meeting the requirements of FERC Order 2000 and the SMD White Paper; and, 3) seeking RTO/ISO status from FERC.

SPP acquired and developed systems to implement an imbalance energy market in 2001. The imbalance energy market was never implemented following FERC's denial of SPP's RTO application in July 2001. The systems continued to sit dormant during SPP's subsequent efforts to combine with the Midwest ISO. After extensive review, SPP's Market Working Group has determined that the most economical means to achieve SPP's market goals is to "dust off" the 2001 market system and update it to meet the needs of SPP's members and customers. Enhancements to the system include revenue inadequacy calculations, and more robust Market Monitoring and Market Power Mitigation systems. The capital costs associated with the above enhancements and start-up approximate $6.6 million (start-up, real-time operations, market monitoring, portal and settlement). Additionally, SPP will incur capital expenditures in 2004 designed to facilitate establishment of a congestion management market in 2005 totaling nearly $5 million (congestion management capital costs are estimated to total $10 million).

The establishment of markets creates additional capital and operating costs in order to successfully meet the Board's goals. Obvious costs are evident in areas such as staffing and computing infrastructure. However, less obvious, but no less expensive, costs will be incurred associated with financial statement audits, 24x7 maintenance contracts to support the market infrastructure, and facilitation of working group and task force meetings, to name a few.

SPP intends to advance other projects in 2004 important to ensuring the continued viability of the Company. The most significant project involves the build-out of a back-up site capable of continuing SPP's critical operations in the event of a catastrophe at SPP's primary facility. The build-out of a back-up operating platform without full capability has been a component of several prior SPP budgets. However, this initiative has been continually delayed due to uncertainty surrounding SPP's ongoing needs. The direction provided by the SPC during 2003 has clarified the requirement for a fully redundant back-up facility to support reliability, tariff and market operations.

2004 will also mark changes to SPP's strategy regarding capital expenditure funding. Historically, with the exception of the 2001 market project, SPP has funded capital expenditures through assessments of the membership. This method resulted in members recognizing all costs associated with a capital project in the year the cost was incurred instead of over the useful life (based on GAAP) of the asset. Though members benefited from lower withdrawal fees, the real beneficiaries were new customers and members that could participate in SPP without incurring a fair portion of the capital costs. The new policy includes funding all capital projects via borrowed funds, thus allowing members and customers to pay their respective fair shares of the costs of a project as the debt amortizes (in line with the GAAP useful life). The benefits will include more predictable tariff and assessment rates, and allocation of costs to future members/customers.

The 2004 budget is submitted both as an operating budget and a capital budget. Additionally, the budget has been segregated to highlight costs most closely associated with various expected projects. The vast majority of operating expenses are included in the "Base Operations" category which includes providing basic services such as reliability coordination, tariff administration, OASIS administration, operating reserve sharing, etc. The next category includes both operating and capital costs specifically assigned to development and implementation of an imbalance energy market consistent with the schedule developed by SPP's Market Working Group. The next two categories contain costs, both capital and operating, specifically associated with market monitoring and mitigation and congestion management. We must understand, however, that these projects will build off of the imbalance energy project in terms of sharing systems, staff, etc.

SALARY/EMPLOYEE BENEFITS

- 2003 staffing is budgeted at 122 full-time salary positions. Currently SPP staff totals 114. End of year salary run rate is estimated to slightly exceed $9 million. Management anticipates increasing headcount during 2004 to 142 full-time salary positions. Specifically the following new positions will be required:
    - Training – 1 technical trainer
    - Operations – 1 EMS engineer, 1 scheduler, 4 market coordinators
    - IT – 2 specialists supporting existing systems, 1 specialist developing/improving systems, 1 database administrator, 1 specialist supporting infrastructure
    - Market Analysis – 2 market analysts and 1 engineer
    - Security (cyber and physical) – 1 security specialist
    - Accounting/Settlements – 2 settlement analysts and 1 credit analyst
    - Executive – 1 general counsel

Annual compensation increase for existing staff will total $660,000 based on a 3% annual merit increase; $196,000 for promotions; and $207,000 for market value adjustments. Compensation for new employees will total $1.3 million. Compensation increases coupled with new hires will increase SPP's annualized salary level at the end of fiscal 2004 to $11.3 million, or $80,500 average salary per employee.

- Healthcare insurance expenses dominate the cost of welfare benefits provided to employees. Benefit costs in 2004 are estimated based on a 17.5 % increase in premiums with the assumption that all new hires take family health coverage. SPP will continue to share the costs of healthcare coverage with employees utilizing an 80/20split (SPP pays 80% of the premium and the employee pays 20% of the premium).

- Funding levels for SPP's defined benefit retirement plan and retiree healthcare are budgeted to increase. These expected increases result from planned staff additions. SPP obtains an actuary report in mid May that is utilized by the Finance Working Group to establish the annual funding level. The 2004 budget includes a $150,000 placeholder for this expected increase. Funding for SPP's matching contribution to the 401(k) plan is estimated at 4.5% of salary.

NEW HIRE JUSTIFICATIONS:

Technical Trainer I	**Grade 30**	**12 Months**

Support training requirements of staff and membership related primarily with development of energy markets. Unable to count on Customer Relations staff to support training needs once phase 1 of energy market is implemented in February 2004.

Market Coordinator

Senior Coordinator (1)	**Grade 55**	**8 Months**
Coordinator III (1)	**Grade 50**	**8 Months**
Coordinator III (2)	**Grade 50**	**12 Months**

Four new Market Coordinators are required to complete the shift necessary to provide 24/7 monitoring, dispatch and operation of the market in fall 2004. Hired in advance of phase III of market implementation to ensure adequate training and to support design, testing and documentation of market processes.

Tariff Scheduler II	**Grade 40**	**12 Months**

An additional Scheduler is needed to perform hourly checkouts during daytime hours to insure that the NSI numbers being sent to the Control Areas are highly accurate. The member Control Areas will be operating from SPP's NSI values as required in increment 2 (April 04) of the market implementation plan.

EMS Engineer II	**Grade 40**	**12 Months**

An additional EMS Engineer will be needed to perform network modeling improvements and maintenance at a level needed for the various phases of market implementation in 2004.

Sr. Database Lead Grade 60 12 Months
The role of this position is Oracle database administration. In the past, SPP has contracted with Alstom ESCA for Remote Database Administration support. This minimal support, consisting of a weekly check of a single Oracle parallel database server running a small Oracle database, costs approximately $65,000 per year. Additional support, such as table indexing, database modification, and performance tuning, is performed on a time and material basis at a rate of $342 per hour. The Remote DBA and T&M support is not available outside of ESCA normal business hours. With the implementation of the Market Systems, SPP will be managing a minimum of six critical Oracle database environments, consisting of large databases in clustered server environments. As these databases will be supporting critical, real-time market and EMS functions, 24x7 support will be required to quickly respond to problems. The cost of contracting with ESCA for this level of support will far exceed the cost of hiring an experienced Oracle database administrator at a competitive salary. This position will report to the Manager, Technology Deployment.

Infrastructure Spec. III Grade 50 12 Months
The role of this position is infrastructure support. The number and complexity of systems being implemented at SPP has increased significantly over the past year. SPP is now installing clustered web, application, and database servers running critical reliability, scheduling, and tariff applications. With the implementation of the Market systems, the complexity of the supported systems will increase even more. The number of supported desktop and laptop PCs is also increasing with the addition of new staff. In addition to system administration, the Infrastructure Department is responsible for installing critical security patches on all systems, a task that has grown greatly with the increased focus on cyber security. An experienced infrastructure support analyst is needed to be able to support the new systems and maintain a high level of reliability and availability of the critical operational systems. This position will report to the Manager, Infrastructure.

Chg Mgmt Admin I Grade 30 12 Months
The role of this position is change management administration. The recent adoption of the NERC Cyber Security Standard requires implementation of a change management process. This process includes the coordination and documentation of all system modifications, including patches, application software upgrades, and database changes. At the same time, SPP is expected to begin preparation for undergoing a SAS-70 audit. The SAS-70 requirements also include a comprehensive change management process. An IT Specialist I support analyst is required to properly administer the change management processes currently being developed. This position will initially report to the Supervisor, Applications Development. The reporting relationship may change as a result of SPP evaluation of SAS-70 requirements.

Applications Support III (2) Grade 50 12 Months
The role of this position is Unix system administration. When the current EMS system administrator was hired, the EMS environment consisted of a pair of DEC servers running OpenVMS and the ESCA EMP Platform. Since then, the workload has grown and changed to where this IT Specialist III system administrator is responsible for the

redundant on-line EMS systems (Unix/EMP), redundant integration/test Unix/EMP systems, and a development Unix/EMP system. With the implementation of the market systems coupled with the requirement of implementing a disaster recovery capability, the number of Unix/Linux systems will more than double. A second experienced Unix system administrator is required to perform the additional tasks. This position will report to the Supervisor, Applications Support.

The role of this position is application support. With the resumption of the SPP Market System project, three senior support staff members were reallocated to be dedicated to the market system project and their application support tasks were reassigned to the remaining, mostly junior staff. These applications are highly complex and critical to SPP's reliability coordination and tariff administration roles. The remaining staff has struggled to absorb the increased workload, especially with the complexity of some of the reassigned applications. While the staff has performed admirably, the increase in workload and complexity has exceeded the abilities of the staff to properly support the critical systems. An additional experienced support analyst is required to restore the level and quality of support being provided prior to the staff reallocation. This position will report to the Supervisor, Applications Support.

Market Analyst II	**Grade 30**	**12 Months**
Market Analyst III	**Grade 40**	**7 Months**
Market Engineer III	**Grade 50**	**7 Months**

Market Analyst and Market Engineer additional positions are being requested to support the additional requirements of the Market Development and Analysis department. The functions that will be needed within this department are: 1) All design functions of Phase 2 (market based congestion management) and possibly Phase 3 (ancillary services). This would include researching all other markets that provide these functions, documenting them and providing analysis of what works about the markets and why. 2) Internal market monitoring (ensuring compliance with market rules by market participants as well as SPP Staff). This will provide a more efficient way to monitor the market on a day-to-day basis and to answer questions from SPP staff, FERC, State Regulatory Bodies, and market participants than contracting for this service. 3) Market power mitigation (expecting some real-time intervention in the market by well-defined rules). FERC is increasingly looking to more real-time interventions to protect against market power abuses. We are intending to try to provide all this function within the SPP organization at a lower cost than contracting the independent market monitor for this service. Other organizations, e.g. ISO New England, PJM, and ERCOT, have a staff of approximately 15 people to support market power mitigation alone. This would bring the staffing in the group to 6.

Security Specialist I	**Grade 20**	**12 Months**

This position will be needed for the Security department to perform assigned responsibilities. The functions of the department are two fold, to protect the company from a cyber perspective and also a physical perspective. The expectation from our members is that we are protecting our computer systems in such a way as to give them confidence that the data and services we provide are genuine and have not been tampered with. Adding this position will provide the staff required to perform our duties effectively. This position will focus primarily on monitoring detection systems for unusual activity.

Accountant II (2)	**Grade 30**	**9 Months**
Credit Analyst	**Grade 30**	**12 Months**

Accountant positions will support transmission tariff and energy market settlements. Addition of the two accountant positions will re-staff the SPP Accounting and Settlement Department to the level previously established in 2001 when SPP was on the verge of implementing imbalance markets.

The credit analyst will enhance the existing credit department staff of one. This staff is responsible for establishing/implementing/enforcing/monitoring of SPP's credit policy to protect owners and customers under the regional tariff.

General Counsel	**Grade 70**	**12 Months**

SPP has historically relied on regulatory counsel and local counsel to address common business and legal issues. The recent process of drafting revisions to SPP's governing documents has illustrated the need for competent in-house counsel to address daily issues as well as manage and direct the activities of outside counsel.

POSITION CHANGE JUSTIFICATIONS:

Administration Department

- **Senior Vice President to Executive Vice President and Chief Operating Officer**
- **Vice President – Operations to Vice President- Market Operations**
- **Vice President – Finance to Vice President and Chief Financial Officer**
  Above changes recommended based on expanded RTO/ISO functional responsibilities.

- **Accountant II to Supervisor Tariff Settlements**
- **Accountant II to Supervisor Corporate Accounting**
  Above changes recommended allowing greater management focus on accounting functions that are substantially different.

- **Human Resource Generalist II to Human Resource Generalist III**
  Expansion of staff and corresponding responsibility of HR personnel necessitates additional experience in this area.

Market Development Department

- **Market Engineer III to Senior Market Engineer**
  Critical nature of market development and implementation requires greater experience level to successfully attain the strategic goals of the company.

Engineering Department

- **Engineer II to Engineer III (2)**
  Greater experience level required to meet the RTO Regional Planning requirements, compliance and monitoring area due to the recent system disturbances, expanded role in processing transmission service requests, and aggregate study methodology process requirements.

<u>Information Technology Department</u>

- **IT Specialist I to IT Specialist II**
  Greater experience level required to responsibilities related to maintaining data points for SPP Reliability operations as well as converting individual member ICCP nodes from OSI to IP protocols

<u>Operations Department</u>

- **Engineer II to Engineer III**
- **Scheduler II to Scheduler III**
  Greater experience required from operation engineering staff to lead efforts to improve models and reliability tools. Increased scheduler knowledge required providing customers accurate and reliable advice related to NSI and tariff issues.

<u>Corporate Affairs Department</u> –

- **Customer Service Associate I to Customer Service Specialist I**
  Existing position is commensurate with lowest level secretarial skills.

<u>EMPLOYEE TRAVEL</u>

SPP responsibilities related to NERC activities as well as participation and facilitation of SPP working groups and task forces necessitates substantial travel. Recent efforts to minimize travel requirements have been beneficial (i.e. VTC, Webex). Factors resulting in an increase in the travel budget in 2004 include:

- **<u>RTO Status</u> –** Staff will be very proactive in communicating with federal and state regulators as well as the individual members of SPP to ensure ample communication among interested and relevant parties
- **<u>Working Groups and Task Forces</u> –** SPP began "re-activating" working groups and task forces in 2003 to assist in the development of a strategic vision for SPP as well as manage and monitor the ongoing business of SPP as a stand-alone entity. These meetings will continue into 2004. Member representatives chair these meetings and tend not to schedule the meetings in Little Rock in an effort to accommodate participants.
- **<u>Training</u> –** Implementation of the imbalance energy market will necessitate travel by SPP staff to provide ample training to members and market participants. Several training sessions will be scheduled in Little Rock; however, on-site visits will be required as well as conducting larger group sessions nearer the member and customer base.

<u>ADMINISTRATIVE</u>

- **Insurance** includes standard insurance coverage to protect the company and the membership from unforeseen events. The largest and most expensive policies provide liability protection ($480,000 annual premium), credit default protection ($115,000 annual premium), and directors & officer coverage ($41,000 annual premium).

- **Audit** includes the annual audit by Deloitte & Touche of SPP's financial statements, accounting processes, and accounting controls. Expense for this service is estimated at $80,000. SPP has not budgeted any funds for a SAS 70 operational audit during 2004.
- **Subscriptions** include a new subscription to Moody's for its default prediction tool to assist in automating SPP's credit process and a subscription to S&P for individual company credit reports. These total $82,000 this is a new expense for the company.

NERC ASSESSMENT

- SPP's assessment in the 2003 budget is $838,000. No data is yet available from NERC regarding its 2004 program and capital costs. A placeholder of $800,000 has been included in the 2004 budget.

SPP/NERC MEETINGS

This item covers the costs associated with hosting meetings. Following is a listing of the various groups for which SPP usually incurs meeting expenses.

- Board of Directors
- Strategic Planning Committee
- Finance Committee
- Regional State Committee
- Compliance Roll-Out
- Compliance Working Group
- Market Project, Increment 1, Phase 1 Training (Meters, Scheduling, and Settlements)
- Market Project, Increment 2, Phase 1 Review (Reliability)
- Market Project, Increment 1, Phase 2 Review (NSI)
- Market Project Training (Settlements, Scheduling, Pricing)
- Market Project Training (Market Monitoring/Market Power Mitigation)
- Market Trials Overview
- Market Trials Review
- Various Task Forces
- Human Resources Committee
- Corporate Governance Committee
- Regional Planning Summits
- TAWG
- MDWG
- GWG
- SPCWG
- NERC IT Meetings
- CIPWG
- ODWG
- Market Working Group
- OMDWG
- BPWG
- ORTF
- ORWG
- MITF
- Operations Meetings
- RTWG

COMMUNICATIONS

- SPP maintains a wide area network and a fully redundant wide area network to facilitate communications with its membership. Specifically these networks support the exchange of real-time ICCP data critical to maintaining grid reliability and security. This network will see enhanced service upon implementation of SPP's energy market in that it will support distribution of NSI data with control areas within SPP's footprint. Services are provided by MCI (primary) and AT&T (backup).

- Budget for teleconferencing and web-casting services is significantly higher than prior years to encourage greater participation in SPP meetings by members and regulators.

LEASES AND MAINTENANCE

- **Maintenance** for the building and building systems including HVAC repairs and maintenance, and security and surveillance systems.
- **Office space** will remain at 2003 levels.
- **Alstom ESCA maintenance agreement** provides basic support during normal business hours with no service level criteria. In the past, this type of support was adequate as there were no serious ramifications of suffering an EMS failure. Recognizing the changing role of SPP in the deregulated marketplace, coupled with the decision by ESCA to release market operations software only in binary form, SPP worked closely with ESCA to develop a maintenance agreement protocol that would meet SPP's 24x7 mission critical support needs. The development and implementation of the imbalance energy market in 2004 eliminates SPP's ability to function with a failure of critical applications. SPP needs to extend the 24x7 ESCA support to the critical functions supported by the EMS network applications, tariff support applications, and the market operations system. The agreement for 2004 will cover critical functions, regardless of the application or database causing the problem, and will have defined priority-based service levels like the prototype agreement tested in 2001. The agreement cost provides for designated, focused support staff at ESCA, the ability to contact the support staff any time of the day or night, and replication of the SPP environment at ESCA to duplicate and resolve problems.

OUTSIDE SERVICES

- Terms for two of SPP's independent board member seats expire each year. SPP has budgeted $100,000 to retain an independent **executive search firm** to conduct a search to identify and recruit candidates to fill the seats expiring in 2004.
- **Consulting, field reviews** covers costs to perform NERC Compliance audits.
- **Consulting, training** covers staff development and training courses facilitated by Human Resources.
- **Consulting, MAPPCOR Database** covers pro-rata costs incurred in the creation of a model by the Midwest Reliability Organization.
- **Impact Studies** reflects costs associated with outsourcing the performance of engineering studies to members and other organizations. The costs are recovered from the beneficiaries of the studies.
- **ESCA and OATI change orders** covers modification to systems, including EMS, OASIS, RTO_SS, and OASIS Automation.
- **The Phase 1 production contract** represents the "run contract" with Accenture for the Commercial Operating System. This expenditure represents re-engagement of Accenture on the contract SPP terminated at the end of 2002. The alternative to re-engagement would entail SPP bringing operation of this system in-house with corresponding increases in staffing and infrastructure overhead.

- **Independent Market Monitor** services will be required by FERC and market participants to ensure an efficient and non-discriminatory market operation devoid of undue influence by individual participants. Operating costs associated with monitoring and mitigation would not begin until December 2004.
- **Consulting, legal (regulatory)** covers costs associated with filings and other regulatory matters.

MISCELLANEOUS INCOME

- **The Vendor Fair** is an event facilitated by SPP's by Corporate Affairs department to introduce vendors familiar with SPP's systems to members and potential market participants. . Income is generated by fees paid by the vendors to participate and are is offset by expenses in the Administrative category in the PR/Mktg Items line. This event should be break-even.
- **Miscellaneous Income for the Engineering Department** results from payments by AEP for SPP to administer AEP's tariff in their eastern region and from tariff customers requiring interconnection and transmission studies. This income is offset by the "Impact Studies" line item in the Outside Services category and other expenses from the Engineering Department.

CAPITAL EXPENDITURES

Major areas in the Capital Budget include:

- **Market Project –** This project will create the SPP Market System, as directed by the Board of Directors and carried out by the Market Working Group. Costs include bringing the 2001 market system up to operational status as well as implementing additional functionality designed by the Market Working Group, and beginning development of congestion management markets for 2005 implementation. Additionally, capital costs to implement market monitoring and market power mitigation systems are included. **Total Cost for 2004: $12, 587,000**.
- **Disaster Recovery Site –** This project will establish a completely redundant Disaster Recovery Site. This site will be able to function completely independently of the main SPP office. **Total Cost for 2004: $1,071,000**.
- **Maintenance CapEx** represent capital expenditures required to maintain SPP's existing equipment and facilities at their current levels. Components of these items are summarized below:
    - **Software Licenses** to support functions of SPP. **Total Cost for 2004: $780,000**.
    - **Hardware** includes PCs for existing and new employees, remodeling costs to provide workspace for staff, security items (firewalls, survellieance equipment), telephone equipment, etc. **Total Cost for 2004: $876,000**.
    - **Servers** includes both replacement and refurbishing servers. **Total Cost for 2004: $229,000.**
    - **Routers & Switches** costs required to support the network backbone, both primary and redundant. **Total Cost for 2004: $245,000.**

DEBT PAYMENTS

- **$25,000,000 Senior Unsecured Notes:** SPP will make a $5,000,000 principal payment on its existing $25,000,000 note in March 2004; interest costs during the year will total $1,687,500.
- **New CapEx Debt:** SPP will obtain financing to fund capital expenditures during the 2004 fiscal year. The debt will be structured to allow SPP to defer principal payments until 2005, though interest costs will be incurred during 2004.
- **Revolving Line of Credit:** SPP will utilize a revolving line of credit with a local lending institution to support cash shortfalls during the year. Interest costs are expected to total $130,000.

Southwest Power Pool
Proposed 2004 Organization Chart

- President
  - Exec. Admin. Assistant
  - General Counsel
  - VP, Finance
    - Exec. Admin. Assistant
    - Financial Services Coordinator
    - Credit Analyst
    - Mgr., Security
      - IT Specialist
      - Facility Coordinator
      - Security Specialist
    - Mgr., Human Resources
      - HR Generalist
      - Secretary
      - Receptionist
    - Mgr., Accounting
      - Accountant (5)
      - Financail Services Coordinator
      - IT Specialist
      - Accountant (2)
  - Mgr., Compliance
  - Director, Regulatory Affairs
    - Mgr, Transmission Policy
      - Engineer (2)
  - Director, Corporate Affairs
    - Mgr. Training
      - Tech. Trainer (2)
      - Tech. Trainer
    - Mgr., Customer Service
      - Cust. Service Specialist (5)
    - Communications Specialist
    - Technical Writer
  - Sr. VP & Corporate Secretary
  - VP, Operations
    - Director, Engineering
      - Admin. Assistant
      - Mgr., Planning
        - Engineer (8)
        - Engineer Associate
      - Spvr., Tariff Studies
        - Engineer (6)
    - Mgr., Mrkt Development
      - Mrkt Analyst (2)
      - Mrkt Engineer
      - Mrkt Analyst (2)
      - Mrkt Engineer
    - Director, IT
      - Mgr, Applications
        - Spvr, Apps. Support
          - IT Specialist 7)
          - IT Specialist (2)
        - Spvr, Apps. Developmt
          - IT Specialist (3)
          - Chg. Mgmt Admin
      - Mgr., Infrastructure
        - IT Specialist (4)
        - IT Specialist
      - Mgr., Tech. Deploymt
        - IT Specialist (3)
        - IT Specialist
        - Database Admin.
      - Spvr, Telecom.
        - Network Admin.
        - IT Specialist
    - Director, Operations
      - Mgr., Mrkt. Ops
        - Coordinator (2)
        - Coordinator (4)
      - Spvr. Ops Eng.
        - Engineer (3)
        - Engineer
      - Spvr. EMS Eng.
        - Engineer (2)
        - Engineer
      - Mgr., Scheduling
        - Coordinator (5)
        - Coordinator
        - Tariff Sched.
      - Mgr., Reliability
        - Coordinator (6)
      - Spvr, Tariff Administration
        - Coordinator (6)

Proposed 2004 SPP Staff:

122 – Full time employees budgeted for 2003

7 – positions currently vacant (in blue)

20 – positions proposed for 2004 (in red)

142 – Total proposed staff for 2004

10/15/2003

Southwest Power Pool

2004 Budget Forecast

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Salaries & Benefits	$ 4,302,180	$ 4,100,725	$ 3,963,916	$ 3,957,960	***$ 16,324,781***
Travel	231,908	203,653	216,619	179,165	***831,345***
Administrative	922,402	191,423	67,468	89,054	***1,270,347***
NERC Assessment	200,000	200,000	200,000	200,000	***800,000***
SPP/NERC Meetings	136,615	128,995	143,620	97,010	***506,240***
Communications	417,793	398,093	412,093	410,093	***1,638,072***
Leases & Maintenance	1,865,347	574,719	659,941	667,361	***3,767,368***
Outside Services	2,633,595	1,545,695	1,587,195	1,807,195	***7,573,680***
GROSS OPERATING EXPENSES	**10,709,840**	**7,343,303**	**7,250,852**	**7,407,838**	***32,711,833***
Miscellaneous Income	(732,000)	(340,000)	(330,000)	(330,000)	***(1,732,000)***
NET OPERATING EXPENSES	**9,977,840**	**7,003,303**	**6,920,852**	**7,077,838**	***30,979,833***
Capital Expenditures	4,665,092	2,946,883	4,480,384	3,796,900	***15,889,259***
Debt Payments on Existing Debt/LoC	5,975,000	62,500	777,750	5,000	***6,820,250***
Debt Payments on 2004 Capital Expenditures	54,601	96,011	159,376	222,211	***532,199***
2004 TOTAL CASH REQUIREMENTS	**$ 20,672,533**	**$ 10,108,697**	**$ 12,338,362**	**$ 11,101,949**	***$ 54,221,541***

Gross Operating Expenses	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	**Total**
2003 Estimate *	5,594,959	5,117,170	5,242,204	5,972,675	21,927,008

Net Operating Expenses	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	**Total**
2003 Estimate *	4,510,514	4,596,689	4,867,204	5,597,675	19,572,082

* contains actual for January - June, and budget for July - December

Southwest Power Pool

2004 Cash Flow Forecast

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Salaries & Benefits	$ 1,684,556	$ 1,314,522	$ 1,303,102	$ 1,392,946	$ 1,366,989	$ 1,340,790	$ 1,311,966	$ 1,321,840	$ 1,330,110	$ 1,331,931	$ 1,302,427	$ 1,323,602	***$ 16,324,781***
Travel	74,320	71,216	86,372	70,100	69,264	64,289	69,553	62,085	84,981	79,776	56,593	42,796	***831,345***
Administrative	802,292	100,189	19,921	144,029	24,781	22,613	23,841	23,126	20,501	40,176	16,926	31,952	***1,270,347***
NERC Assessment	200,000	-	-	200,000	-	-	200,000	-	-	200,000	-	-	***800,000***
SPP/NERC Meetings	40,355	47,395	48,865	49,245	32,530	47,220	21,480	46,685	75,455	40,480	32,470	24,060	***506,240***
Communications	126,720	148,553	142,520	132,520	133,053	132,520	136,520	139,053	136,520	136,520	137,053	136,520	***1,638,072***
Leases & Maintenance	1,511,648	82,592	271,107	188,877	180,677	205,165	310,827	179,677	169,437	173,377	170,177	323,807	***3,767,368***
Outside Services	1,654,298	494,898	484,398	554,398	484,898	506,398	515,398	528,898	542,898	516,398	487,898	802,898	***7,573,680***
GROSS OPERATING EXPENSES	**6,094,189**	**2,259,365**	**2,356,285**	**2,732,115**	**2,292,192**	**2,318,995**	**2,589,585**	**2,301,364**	**2,359,902**	**2,518,658**	**2,203,544**	**2,685,635**	***32,711,833***
Miscellaneous Income	(110,000)	(512,000)	(110,000)	(110,000)	(110,000)	(120,000)	(110,000)	(110,000)	(110,000)	(110,000)	(110,000)	(110,000)	***(1,732,000)***
NET OPERATING EXPENSES	**5,984,189**	**1,747,365**	**2,246,285**	**2,622,115**	**2,182,192**	**2,198,995**	**2,479,585**	**2,191,364**	**2,249,902**	**2,408,658**	**2,093,544**	**2,575,635**	***30,979,833***
Debt Payments	20,408	20,868	5,988,325	52,287	50,664	55,560	58,430	60,734	817,962	72,729	75,036	79,446	***7,352,449***
2004 TOTAL OPERATING CASH REQUIREMENTS	**$ 6,004,597**	**$ 1,768,233**	**$ 8,234,610**	**$ 2,674,402**	**$ 2,232,856**	**$ 2,254,555**	**$ 2,538,015**	**$ 2,252,098**	**$ 3,067,864**	**$ 2,481,387**	**$ 2,168,580**	**$ 2,655,081**	***$ 38,332,282***
Revenue	4,440,659	2,824,710	3,130,017	3,228,584	3,120,178	3,026,292	3,333,259	3,129,983	3,033,182	3,342,161	3,025,278	3,146,319	***38,780,622***
Cash Surplus/(Deficit)	(1,563,938)	1,056,477	(5,104,593)	554,182	887,322	771,737	795,244	877,885	(34,682)	860,774	856,698	491,238	
Line of Credit Balance	(1,563,938)	(507,462)	(5,612,055)	(5,057,873)	(4,170,551)	(3,398,815)	(2,603,571)	(1,725,686)	(1,760,369)	(899,595)	(42,897)	448,340	
	(7,819.69)	(2,537.31)	(28,060.28)	(25,289.37)	(20,852.76)	(16,994.07)	(13,017.86)	(8,628.43)	(8,801.84)	(4,497.98)	(214.49)	2,241.70	

Southwest Power Pool

Budget Comparison

	2001 Actual	2002 Actual	2003 Estimate *	2004 Budget	2003-04 Change	% Change
Salaries & Benefits	$ 10,085,042	$ 10,983,822	$ 12,542,545	$ 16,324,781	$ 3,782,236	30.16%
Travel	633,209	759,573	706,340	831,345	125,005	17.70%
Administrative	1,405,116	1,186,267	877,010	1,270,347	393,337	44.85%
NERC Assessment	868,398	810,130	838,375	800,000	(38,375)	-4.58%
SPP/NERC Meetings	250,417	108,400	218,326	506,240	287,914	131.87%
Communications	644,539	1,034,463	1,423,148	1,638,072	214,924	15.10%
Leases & Maintenance	761,703	1,449,528	1,458,166	3,767,368	2,309,202	158.36%
Outside Services	2,769,976	10,241,571	3,909,315	7,573,680	3,664,365	93.73%
GROSS OPERATING EXPENSES	**17,418,400**	**26,573,754**	**21,973,225**	**32,711,833**	**10,738,608**	**48.87%**
Miscellaneous Income	(3,557,427)	(2,507,409)	(2,354,927)	(1,732,000)	622,927	-26.45%
NET OPERATING EXPENSES	**13,860,973**	**24,066,345**	**19,618,298**	**30,979,833**	**11,361,535**	**57.91%**
Capital Expenditures	23,043,287	1,391,279	1,815,628	15,889,259	14,073,631	775.14%
Debt Payments	1,294,746	2,031,250	1,875,000	7,352,449	5,477,449	292.13%
TOTAL CASH REQUIREMENTS	**$ 38,199,006**	**$ 27,488,874**	**$ 23,308,926**	**$ 54,221,541**	**$ 30,912,615**	**132.62%**

* contains actual for January - June, and budget for July - December

Southwest Power Pool

2004 Budget

by Category

	Base Operations	Markets - Energy Imbalance	Markets - Market Monitoring and Market Power Mitigation	Markets - Congestion Management	**Total**
Salaries & Benefits	$ 14,562,037	$ 1,645,615	$ 117,129	$ -	***16,324,781***
Travel	530,359	300,986	-	-	***831,345***
Administrative	1,270,347	-	-	-	***1,270,347***
NERC Assessment	800,000	-	-	-	***800,000***
SPP/NERC Meetings	225,850	274,390	6,000	-	***506,240***
Communications	1,638,072	-	-	-	***1,638,072***
Leases & Maintenance	1,922,536	1,844,832	-	-	***3,767,368***
Outside Services	2,403,680	4,770,000	400,000	-	***7,573,680***
GROSS OPERATING EXPENSES	**23,352,881**	**8,835,823**	**523,129**	**-**	***32,711,833***
Miscellaneous Income	(1,732,000)	-	-	-	***(1,732,000)***
NET OPERATING EXPENSES	**21,620,881**	**8,835,823**	**523,129**	**-**	***30,979,833***
Capital Expenditures	3,036,804	5,052,455	3,000,000	4,800,000	***15,889,259***
Debt Payments	6,972,275	198,674	97,500	84,000	***7,352,449***
2004 TOTAL CASH REQUIREMENTS	**$ 31,629,960**	**$ 14,086,952**	**$ 3,620,629**	**$ 4,884,000**	***$ 54,221,541***

Salaries & Benefits
2004 Budget

Account	January	February	March	April	May	June	July	August	September	October	November	December	2004 Total
Existing Salaries Total	776,544	776,544	776,544	776,544	776,544	776,544	776,544	776,544	776,544	776,544	776,544	776,544	9,318,528
Existing Staff Merit Increase Total	21,491	21,491	21,491	21,491	21,491	21,491	21,491	21,491	21,491	21,491	21,491	21,491	257,892
Existing Staff Promotions Total	15,650	15,650	15,650	15,850	15,850	15,850	15,850	15,850	15,850	21,283	16,283	16,283	195,899
Structural Adjustments Total	17,220	17,220	17,220	17,220	17,220	17,220	17,220	17,220	17,220	17,220	17,220	17,220	206,640
Staff Additions Total	75,257	87,657	87,818	95,868	109,335	120,602	120,602	120,602	120,602	120,602	120,602	120,602	1,300,149
Social Security (6.2%, limit 87,000) Total	71,281	56,974	56,984	57,497	58,332	59,031	59,031	59,031	59,031	59,368	59,058	59,058	714,676
Medicare (1.45%, no limit) Total	16,670	13,325	13,327	13,446	13,641	13,804	13,804	13,804	13,804	13,883	13,811	13,811	167,130
Federal Unemployment Insurance Total	10,000	-	-	-	-	-	-	-	-	-	-	-	10,000
State Unemployment Insurance Total	45,000	-	-	-	-	-	-	-	-	-	-	-	45,000
Workers' Compensation Total	20,000	-	-	-	-	-	-	-	-	-	-	-	20,000
Savings Plan (4.5%) Total	51,736	41,353	41,360	41,731	42,337	42,844	42,844	42,844	42,844	43,089	42,864	42,864	518,710
Medical Plan Total	92,048	93,048	93,048	95,048	97,048	99,048	99,048	99,048	99,048	99,048	99,048	99,048	1,163,576
Dental Plan Total	12,690	12,784	12,784	12,972	13,160	13,348	13,348	13,348	13,348	13,348	13,348	13,348	157,826
Life Insurance Total	241	193	193	195	198	200	200	200	200	201	200	200	2,421
Board Compensation Total	-	18,000	18,000	108,000	-	18,000	-	18,000	18,000	18,000	-	18,000	234,000
Incentive/Retention Compensation Total	-	-	-	-	-	-	-	-	-	-	-	-	-
Pension Funding Total	78,000	78,000	78,000	78,000	78,000	78,000	78,000	78,000	78,000	78,000	78,000	78,000	936,000
Retiree Medical Benefits Funding Total	36,334	36,333	36,333	36,334	36,333	36,333	36,334	36,333	36,333	36,334	36,333	36,333	436,000
Continuing Education Total	42,240	21,950	32,350	20,750	34,500	21,475	17,650	9,525	17,795	13,520	7,625	10,800	250,180
Hiring Expenses Total	17,000	-	-	2,000	10,000	5,000	-	-	-	-	-	-	34,000
Relocation Expenses Total	42,000	24,000	2,000	-	43,000	2,000	-	-	-	-	-	-	113,000
Employee Retirement Total	243,154	-	-	-	-	-	-	-	-	-	-	-	243,154
Grand Total	1,684,556	1,314,522	1,303,102	1,392,946	1,366,989	1,340,790	1,311,966	1,321,840	1,330,110	1,331,931	1,302,427	1,323,602	16,324,781

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2003 Estimate *	978,125	917,135	946,573	1,057,336	882,393	1,077,267	1,019,986	974,710	1,001,034	1,047,357	1,559,989	1,080,640	**12,542,545**

* contains actual for January - June, and budget for July - December

Employee Travel
2004 Budget

Department	1Q	2Q	3Q	4Q	2004 Budget
Administration Total	63,216	65,453	58,350	58,533	245,552
Corporate Affairs Total	30,700	18,100	30,550	22,150	101,500
Engineering Total	24,975	24,975	24,975	24,975	99,900
Information Technology Total	59,945	37,655	60,220	36,705	194,525
Markets Total	15,000	16,100	12,600	7,200	50,900
Operations Total	26,172	30,270	18,024	18,502	92,968
Regulatory Affairs Total	11,900	11,100	11,900	11,100	46,000
Grand Total	231,908	203,653	216,619	179,165	831,345

1Q	2Q	3Q	4Q	Total
91,644	255,545	155,403	150,689	**653,281**
116,625	189,528	207,965	245,455	**759,573**
159,025	162,105	194,470	190,740	**706,340**

Administrative
2004 Budget

Account	1Q	2Q	3Q	4Q	2004 Budget	2003 Estimate *
Annual Audit Total	80,000	-	-	-	80,000	29,000
Badging Supplies Total	1,063	1,595	-	-	2,658	-
Banking Charges Total	4,500	4,500	4,500	4,500	18,000	22,138
Business Cards Total	500	500	500	500	2,000	1,239
Copier Supplies Total	1,500	1,500	1,500	1,500	6,000	7,405
Employee Events Total	5,299	16,804	4,539	23,716	50,358	28,200
Energy Usage Total	12,000	13,000	15,500	12,000	52,500	65,400
Equipment Total	3,400	-	-	-	3,400	-
Freight Total	3,750	3,750	3,750	3,750	15,000	14,185
Hardware Total	-	2,975	-	-	2,975	-
Insurance (Credit) Total	-	115,000	-	-	115,000	116,190
Insurance (Dir. & Officer) Total	41,000	-	-	-	41,000	34,080
Insurance (Excess Liability) Total	480,000	-	-	-	480,000	336,009
Insurance (GL/Contents) Total	50,700	-	-	-	50,700	42,199
Insurance (PBGC) Total	-	-	-	15,000	15,000	-
Managers Fund Total	1,875	1,875	1,875	1,875	7,500	4,443
Mktg/PR/Promo Items Total	3,700	2,700	3,600	1,700	11,700	3,000
Office Expense Total	16,449	16,449	16,449	16,449	65,796	60,491
Parking Fees Total	960	-	-	-	960	-
Postage Total	990	990	990	990	3,960	4,520
Professional Dues Total	8,864	1,270	2,890	2,100	15,124	8,230
Property Tax Total	76,000	-	-	-	76,000	75,388
Software Total	-	2,250	2,000	2,000	6,250	-
Software Licenses Total	10,152	875	8,125	1,774	20,926	-
Subscriptions Total	84,700	5,390	1,250	1,200	92,540	7,543
Use Tax Total	35,000	-	-	-	35,000	17,350
Grand Total	922,402	191,423	67,468	89,054	1,270,347	877,010

NERC Assessment
2004 Budget

				2004			2004	2003
Department	**Group**	**Account**	**1Q**	**2Q**	**3Q**	**4Q**	**Budget**	**Estimate ***
Administration	Compliance	NERC Assessment	200,000	200,000	200,000	200,000	800,000	838,375

SPP/NERC Meetings
2004 Budget

Department	Meeting	# of Meetings	1Q	2Q	3Q	4Q	2004 Budget	2003 Estimate *
Administration	Board of Directors	6	10,000	10,000	10,000	10,000	40,000	17,553
Operations	Business Practices WG	6	2,480	1,240	2,480	1,240	7,440	6,600
Corporate Affairs	Communications	12	450	450	450	450	1,800	-
Administration	Compliance Roll-Out	1	-	3,600	-	-	3,600	3,772
Administration	Compliance Working Group	3	1,100	-	1,100	1,100	3,300	2,400
	Conferences - Misc.	0	-	-	-	-	-	1,383
	Congestion Management WG	0	-	-	-	-	-	6,371
Operations	Coordinator Internal Meetings	4	250	250	250	250	1,000	-
Administration	Corporate Governance Committee	1	-	-	3,000	-	3,000	-
	Critical Infrastructure Prot. WG	0	-	-	-	-	-	4,400
Corporate Affairs	Customer Relations	12	150	150	150	150	600	-
	Employee Benefits WG	0	-	-	-	-	-	2,550
Administration	Finance Committee	3	3,000	3,000	3,000	-	9,000	2,550
	Generation Availability WG	0	-	-	-	-	-	1,030
	Generation WG	0	-	-	-	-	-	800
Administration	Human Resources Committee	2	-	3,000	3,000	-	6,000	-
Corporate Affairs	Legal	12	150	150	150	150	600	-
Operations	Market Implementation TF	9	3,930	3,930	2,620	1,310	11,790	-
	Market Overview Class	0	-	-	-	-	-	22,000
	Market Operations Training	0	-	-	-	-	-	3,057
Corporate Affairs	Market Training Follow-up	1	-	-	-	2,000	2,000	-
Corporate Affairs	Market Trials Overview	1	-	-	-	10,000	10,000	-
Markets	Market WG	17	25,000	25,000	20,000	15,000	85,000	33,836
Markets	Market WG Task Forces	15	12,100	9,900	4,400	4,400	30,800	-
	Members	0	-	-	-	-	-	5,000
Corporate Affairs	Meter, Scheduling & Settlement Trai	1	6,000	-	-	-	6,000	-
	Model Development WG	0	-	-	-	-	-	800
Corporate Affairs	MMMPM Training	1	-	-	6,000	-	6,000	-
Information Technology	NERC Meeting Reimb.	6	4,540	2,270	4,540	2,270	13,620	638
Corporate Affairs	NSI Training	1	2,000	-	-	-	2,000	-
	Operational Data WG	0	-	-	-	-	-	1,275
Operations	OMDWG	3	1,400	1,300	-	1,300	4,000	2,550
Operations	Operations Off-site Meetings	4	2,200	2,200	2,200	2,200	8,800	-

Department	Meeting	# of Meetings	1Q	2Q	3Q	4Q	2004 Budget	2003 Estimate *
Operations	ORTF	5	1,275	2,550	1,275	1,275	6,375	-
Operations	ORWG	5	4,350	2,175	2,175	2,175	10,875	11,541
Operations	ORWG Conference Calls/Webcast	4	400	400	400	400	1,600	-
Corporate Affairs	Phase 1, Increment 3 Training	1	-	-	10,000	-	10,000	-
	Policy Committee	5	7,000	3,500	3,500	3,500	17,500	2,858
Engineering	Regional Planning Summits	2	-	10,000	10,000	-	20,000	-
Administration	Regional State Committee	4	6,000	6,000	6,000	6,000	24,000	-
	Regional Pricing	0	-	-	-	-	-	9,939
Corporate Affairs	Reliability Overview	1	10,000	-	-	-	10,000	-
Corporate Affairs	Rental of Computers for Training	1	-	-	8,000	-	8,000	-
Regulatory Affairs	RTWG Meetings	14	15,640	11,730	11,730	15,640	54,740	-
Corporate Affairs	Settlement, Scheduling, Pricing Trai	1	-	-	10,000	-	10,000	-
Administration	Settlements Task Force	4	1,200	1,200	1,200	1,200	4,800	-
Information Technology	SPP CIP Working Group	6	2,000	4,000	2,000	4,000	12,000	-
Engineering	SPP GWG	4	1,100	1,100	1,100	1,100	4,400	-
Engineering	SPP MDWG	6	1,100	2,200	1,100	2,200	6,600	1,600
Information Technology	SPP ODWG	4	1,500	1,500	1,500	1,500	6,000	-
Engineering	SPP SPCWG	4	1,100	1,100	1,100	1,100	4,400	-
Engineering	SPP TAWG	6	2,200	1,100	2,200	1,100	6,600	9,898
Administration	Strategic Planning Committee	4	6,000	3,000	6,000	3,000	18,000	7,125
	System Operations WG	0	-	-	-	-	-	965
Engineering	Task Forces	8	1,000	1,000	1,000	1,000	4,000	30,031
	Vendor Fair	1	-	10,000	-	-	10,000	8,804
	Webcasts	0	-	-	-	-	-	5,000
	XML Class	0	-	-	-	-	-	12,000
			136,615	**128,995**	**143,620**	**97,010**	**506,240**	**218,326**

	1Q	2Q	3Q	4Q	Total
2001 Actual	65,063	93,478	59,896	31,979	**250,417**
2002 Actual	19,695	35,189	12,003	41,514	**108,401**
2003 Estimate *	19,462	66,409	59,880	72,575	**218,326**

* contains actual for January - June, and budget for July - December

Communications
2004 Budget

Department	Account	1Q	2Q	3Q	4Q	2004 Budget	2003 Estimate *
Information Technology	Internet - ARIN Registry	100	-	-	-	100	-
Information Technology	Internet Service - Employees	8,790	8,790	8,790	8,790	35,160	28,493
Information Technology	Internet Service - MCI	4,950	4,950	4,950	4,950	19,800	18,590
Information Technology	Internet Service - TelCove	3,600	3,600	3,600	3,600	14,400	12,872
Information Technology	Cable TV - Coordination Center	225	225	225	225	900	766
Information Technology	Data - Additional POTS Lines	990	990	990	990	3,960	-
Information Technology	Data - SBC Dialin Circuit	5,580	5,580	5,580	5,580	22,320	16,200
Information Technology	Pagers	19,200	-	-	-	19,200	17,404
Information Technology	Phone - Cellular Service	12,300	12,300	12,300	12,300	49,200	48,222
Information Technology	Phone - Satellite Service	495	495	495	495	1,980	1,935
Information Technology	Phone - Hand Sets	533	533	533	533	2,132	-
Information Technology	Phone - Headsets	450	450	450	450	1,800	-
Information Technology	Phone - Conference phones	2,000	-	2,000		4,000	-
Information Technology	Video - Teleconferencing Circuit	5,400	5,400	5,400	5,400	21,600	39,711
Information Technology	Video - Teleconferencing Minutes	1,800	1,800	1,800	1,800	7,200	-
Information Technology	Voice - Audio Conference/WebCast	45,000	45,000	45,000	45,000	180,000	40,766
Information Technology	Voice - Calling Card, MCI	630	630	630	630	2,520	935
Information Technology	Voice - Disaster, SBC	450	450	450	450	1,800	-
Information Technology	Voice - LD 800 (INWATS), MCI	4,800	4,800	4,800	4,800	19,200	5,932
Information Technology	Voice - LD Dial Out, MCI	13,500	13,500	13,500	13,500	54,000	44,532
Information Technology	Voice - Phone, TelCove (Disaster Recovery Site)	1,350	1,350	1,350	1,350	5,400	9,441
Information Technology	Voice - PRI Phone Circuit, SBC	18,900	18,900	18,900	18,900	75,600	61,725
Information Technology	Voice - Second PRI, SBC (Add'l Lines)	5,580	5,580	5,580	5,580	22,320	-
Information Technology	NERCNet (Disaster Recovery Site)	4,500	4,500	4,500	4,500	18,000	-
Information Technology	NERCNet - SPP Corp	4,500	4,500	4,500	4,500	18,000	14,723
Information Technology	Data - Backhaul, TelCove	2,070	2,070	2,070	2,070	8,280	9,000
Information Technology	Data - CISCO Aironet (Wireless) Upgrade	10,000	-	-	-	10,000	-
Information Technology	Data - SPPNet, AT&T	86,700	86,700	86,700	86,700	346,800	341,107
Information Technology	Data - SPPNet, AT&T (Disaster Recovery Site)	1,800	5,400	5,400	5,400	18,000	27,925
Information Technology	Data - SPPNet, MCI	147,600	147,600	147,600	147,600	590,400	682,870
Information Technology	Data - SPPNET, New Members	4,000	12,000	24,000	24,000	64,000	-
Information Technology Total		417,793	398,093	412,093	410,093	1,638,072	1,423,148
Grand Total		417,793	398,093	412,093	410,093	1,638,072	1,423,148

Communications
2004 Budget

Department	Account	1Q	2Q	3Q	4Q	2004 Budget	2003 Estimate *
		1Q	2Q	3Q	4Q	Total	
	2001 Actual	139,298	158,807	157,868	170,531	**487,207**	
	2002 Actual	300,656	298,470	188,787	246,559	**733,816**	
	2003 Estimate *	254,023	285,835	453,645	429,645	**1,169,125**	

* contains actual for January - June, and budget for July - December

Leases & Maintenance
2004 Budget

Department	Group	Subaccount	1Q	2Q	3Q	4Q	2004 Budget	2003 Estimate *
Administration	Administration	Camera surveilliance system (conting.)	1,200	-	-	-	1,200	700
Administration	Administration	CheckPoint / Nokia Support	23,425	-	-	-	23,425	-
Administration	Administration	Door access system repair (conting.)	3,500	-	-	-	3,500	-
Administration	Administration	Fire suppression repair (conting.)	700	-	-	-	700	1,000
Administration	Administration	Firewall & IDS Log Analyzer	1,063	-	-	-	1,063	-
Administration	Administration	Generator fuel	600	600	600	600	2,400	500
Administration	Administration	Generator repair & batteries (conting.)	4,600	-	-	-	4,600	4,600
Administration	Administration	HVAC repair (conting.)	5,000	-	-	-	5,000	9,327
Administration	Administration	Incident Response Kit	1,500	-	-	-	1,500	-
Administration	Administration	Lease, copier	18,600	18,600	18,600	18,600	74,400	59,505
Administration	Administration	Lease, LR office	148,500	148,500	148,500	148,500	594,000	572,709
Administration	Administration	MAILSweeper / IMAGEManager	-	-	2,800	-	2,800	-
Administration	Administration	Maintenance (HVAC)	-	5,000	-	-	5,000	-
Administration	Administration	Postage Meter	800	-	-	-	800	-
Administration	Administration	Red Hat Network (Linux)	1,000	-	-	-	1,000	-
Administration	Administration	Scanner X	1,500	-	-	-	1,500	-
Administration	Administration	SecurID	3,200	-	-	-	3,200	-
Administration	Administration	Security Cameras (Telco & CR)	1,600	-	-	-	1,600	-
Administration	Administration	Sophos	-	-	-	3,000	3,000	-
Administration	Administration	Update HVAC & Power Drawings for CR	1,063	-	-	-	1,063	-
Administration	Human Resources	Software License Renewal	3,000	-	3,000	-	6,000	5,245
Administration Total			220,851	172,700	173,500	170,700	737,751	653,586
Engineering	Engineering	Software License Renewal	1,500	1,500	1,500	1,500	6,000	-
Engineering	Software	PTI-MUST (Engineering)	-	24,000	-	-	24,000	1,000
Engineering	Software	PTI-PSS/E (Engineering)	10,000	-	-	-	10,000	1,000
Engineering	Software	VAST (Engineering)	10,000	-	-	-	10,000	-
Engineering Total			21,500	25,500	1,500	1,500	50,000	2,000
Information Technology	Hardware	CISCO Load Balancers (renew 2006)	-	-	-	-	-	-
Information Technology	Hardware	Compaq (EMS)	-	-	140,450	-	140,450	-
Information Technology	Hardware	Liebert - UPS Bat Rplc, Backup Site	-	-	-	-	-	-
Information Technology	Hardware	Liebert - UPS Bat Rplc, Primary Site	-	12,000	-	-	12,000	-
Information Technology	Hardware	Liebert - UPS Maint, Backup Site	13,500	-	-	-	13,500	-
Information Technology	Hardware	Liebert - UPS Maint, Primary Site	-	11,800	-	-	11,800	-
Information Technology	Hardware	Mapboard	-	-	-	-	-	2,871
Information Technology	Hardware	Printer Maintenance	1,500	1,500	1,500	1,500	6,000	4,093
Information Technology	Hardware	Security Center	-	-	-	-	-	1,000
Information Technology	Hardware	Time & Materials	3,000	3,000	3,000	3,000	12,000	1,400
Information Technology	Hardware	UPS Replacements	1,500	1,500	1,500	1,500	6,000	16,000

Leases & Maintenance
2004 Budget

Department	Group	Subaccount	1Q	2Q	3Q	4Q	2004 Budget	2003 Estimate *
Information Technology	Miscellaneous	Backup Media	4,500	4,500	4,500	4,500	18,000	18,000
Information Technology	Miscellaneous	Hdwe/Cables/Etc.	3,000	3,000	3,000	3,000	12,000	14,539
Information Technology	Miscellaneous	Incr. PC Upgrades	1,500	1,500	1,500	1,500	6,000	3,150
Information Technology	Miscellaneous	Reference Manuals	600	600	600	600	2,400	1,200
Information Technology	Miscellaneous	Technet subscription (qty=4)	-	-	5,000	-	5,000	-
Information Technology	Miscellaneous	Voice Recorder DVD Media	500	-	-	-	500	-
Information Technology	OASIS	Digital Certificates	6,300	6,300	6,300	6,300	25,200	11,746
Information Technology	Router	CISCO Member Router Maintenance	42,000	-	-	-	42,000	-
Information Technology	Router	CISCO SPP Router Maintenance	55,000	-	-	-	55,000	-
Information Technology	Software	ESCA AIMMS/CPLEX Annual Maint.	8,500	-	-	-	8,500	8,073
Information Technology	Software	ESCA Platinum (24x7 AEP OASIS)	201,658	-	-	-	201,658	-
Information Technology	Software	ESCA Platinum (24x7 EMS/OAS/OASIS)	289,252	-	-	-	289,252	538,384
Information Technology	Software	ESCA Platinum (24x7 MOS)	105,677	317,031	317,031	317,031	1,056,770	-
Information Technology	Software	ESCA Silver (5x9 EMS/OAS/OASIS)	244,237	-	-	-	244,237	-
Information Technology	Software	ESCA Silver (5x9 MOS)	634,062	-	-	-	634,062	-
Information Technology	Software	EtherPeek	1,000	-	-	-	1,000	-
Information Technology	Software	IntelliSync Annual Maintenance	1,250	-	-	-	1,250	-
Information Technology	Software	Lodestar	-	-	-	102,000	102,000	102,000
Information Technology	Software	MicroGads	-	-	-	-	-	-
Information Technology	Software	Nostradamus	-	9,000	-	-	9,000	-
Information Technology	Software	Oracle Silver Service	-	-	-	-	-	41,113
Information Technology	Software	OSI Firewall Firmware	2,000	-	-	-	2,000	-
Information Technology	Software	Red Hat Subscription (MOS Systems)	480	288	-	-	768	500
Information Technology	Software	SAS	-	4,500	-	-	4,500	4,200
Information Technology	Software	Siebel	-	-	-	52,000	52,000	52,000
Information Technology	Software	TOAD	-	-	-	1,300	1,300	-
Information Technology	Software	TOCK Software	-	-	-	-	-	-
Information Technology	Software	T-Plan	-	-	-	-	-	-
Information Technology	Software	UniCA ICCP Data Analyser	-	-	-	930	930	-
Information Technology	Software	VMWare Annual Maintenance	1,980	-	-	-	1,980	-
Information Technology	Software	XML SPY	-	-	560	-	560	-
Information Technology	Software	Zone Alarm Pro (K. Perry, renew 2005)	-	-	-	-	-	-
Information Technology Total			1,622,996	376,519	484,941	495,161	2,979,617	820,269
Grand Total			1,865,347	574,719	659,941	667,361	3,767,368	1,475,855

1Q	2Q	3Q	4Q	Total

Leases & Maintenance
2004 Budget

Department	Group	Subaccount	1Q	2Q	3Q	4Q	2004 Budget	2003 Estimate *
		2001 Actual	305,449	922,441	417,141	(1,343,056)	**301,975**	
		2002 Actual	745,711	1,276,708	856,443	601,922	**3,480,784**	
		2003 Estimate *	701,378	208,216	207,461	341,111	**1,458,166**	

* contains actual for January - June, and budget for July - December

Outside Services
2004 Budget

Department	Group	Subaccount	1Q	2Q	3Q	4Q	2004 Total	2003 Estimate *
Administration	Accounting	Consulting, accounting	-	-	-	-	-	12,865
Administration	Accounting	Payroll Administration	-	-	-	-	-	2,013
Administration	Administration	Board of Directors search	-	-	100,000	-	100,000	-
Administration	Administration	Map Physical Facilities	-	-	-	-	-	2,000
Administration	Administration	Merger Costs	-	-	-	-	-	132,689
Administration	Compliance	Consulting, Field Reviews	-	25,000	26,000	39,000	90,000	139,066
Administration	Compliance	Consulting, MAPPCOR Database	75,000	15,000	15,000	15,000	120,000	64,000
Administration	Executive	Consulting	-	-	-	-	-	143,374
Administration	Human Resources	401(k) Savings Plan	-	-	-	-	-	26,019
Administration	Human Resources	Consulting, benefits	49,570	8,670	12,670	8,670	79,580	87,742
Administration	Human Resources	Consulting, training	6,000	6,000	6,000	6,000	24,000	20,000
Administration	Security	Consulting, security	2,500	2,500	2,500	2,500	10,000	-
Administration Total			133,070	57,170	162,170	71,170	423,580	629,768
Corporate Affairs	Corporate Affairs	Annual Report	1,000	20,000	-	1,000	22,000	530
Corporate Affairs	Legal	Legal	15,000	15,000	15,000	15,000	60,000	133,172
Corporate Affairs	Training	Consulting, training development	-	-	-	-	-	-
Corporate Affairs Total			16,000	35,000	15,000	16,000	82,000	133,702
Engineering	Tariff Studies	Impact Studies	100,000	100,000	100,000	100,000	400,000	358,201
Engineering	Engineering	AEP Project	-	-	-	-	-	221,617
Engineering	Engineering	Consulting, engineering	6,000	26,000	6,000	6,000	44,000	14,000
Engineering Total			106,000	126,000	106,000	106,000	444,000	593,818
Information Technology	Information Technology	Computer Consulting	24,000	24,000	24,000	24,000	96,000	94,998
Information Technology	Information Technology	COS Operations	-	-	-	-	-	1,458,720
Information Technology	Information Technology	ESCA On-site Training	-	-	-	-	-	31,577
Information Technology	Information Technology	ESCA - Secure ICCP upgrade	20,000	-	-	-	20,000	-
Information Technology	Information Technology	ESCA - MOS Integration	500,000	-	-	-	500,000	-
Information Technology	Information Technology	ESCA - OASIS Change Orders	25,000	25,000	25,000	25,000	100,000	100,000
Information Technology	Information Technology	ESCA - OASIS Automation Change Orde	30,000	30,000	30,000	30,000	120,000	180,000
Information Technology	Information Technology	ESCA - OASIS Automation (AEP Project	200,000	-	-	-	200,000	-
Information Technology	Information Technology	OATI Change Orders	60,000	60,000	60,000	60,000	240,000	219,231
Information Technology	Information Technology	Pomeroy Consulting	7,500	7,500	5,000	5,000	25,000	19,515
Information Technology	Information Technology	RTO_SS Runtime/OATI Scheduling	75,000	95,000	105,000	105,000	380,000	296,337
Information Technology	Information Technology	Secure Vision Support	3,100	3,100	2,100	2,100	10,400	2,000
Information Technology	Information Technology	Voice Recorder	1,000	-	-	-	1,000	-
Information Technology	Information Technology	Weather Forecast	2,925	2,925	2,925	2,925	11,700	19,722
Information Technology Total			948,525	247,525	254,025	254,025	1,704,100	2,422,100
Markets	Markets	Phase 1 Production Contract	1,280,000	930,000	930,000	930,000	4,070,000	-
Markets	Markets	Independent Market Monitor	-	-	-	300,000	300,000	4,598

Department	Group	Subaccount	1Q	2Q	3Q	4Q	2004 Total	2003 Estimate *
Markets Total			1,280,000	930,000	930,000	1,230,000	4,370,000	4,598
Operations	Operations	Training courses	-	-	-	-	-	329
Operations Total			-	-	-	-	-	329
Regulatory Affairs	Regulatory Affairs	Consulting, legal	120,000	130,000	120,000	130,000	500,000	125,000
Regulatory Affairs	Regulatory Affairs	Consulting, rates (regulatory)	30,000	20,000	-	-	50,000	-
Regulatory Affairs Total			150,000	150,000	120,000	130,000	550,000	125,000
Grand Total			2,633,595	1,545,695	1,587,195	1,807,195	7,573,680	3,909,315

Miscellaneous Income
2004 Budget

Department	Account	1Q	2Q	3Q	4Q	2004 Total	2003 Estimate *
Administration	Employee Services - MISO	-	-	-	-	-	(673,677)
Administration	Interest	-	-	-	-	-	(12,436)
Administration	Miscellaneous	-	-	-	-	-	(47,726)
Administration Total		**-**	**-**	**-**	**-**	**-**	**(733,839)**
Corporate Affairs	Vendor Fair	-	(10,000)	-	-	(10,000)	(11,025)
Corporate Affairs Total		**-**	**(10,000)**	**-**	**-**	**(10,000)**	**(11,025)**
Information Technology	AEP OASIS Project	(402,000)	-	-	-	(402,000)	-
Information Technology	ARS Reimbursement	-	-	-	-	-	(15,249)
Information Technology	Redundant Router & Switch	-	-	-	-	-	(150,008)
Information Technology	SPPNet Reimbursement	-	-	-	-	-	(61,098)
Information Technology Total		**(402,000)**	**-**	**-**	**-**	**(402,000)**	**(226,355)**
Engineering	Impact Studies	(180,000)	(180,000)	(180,000)	(180,000)	(720,000)	(622,489)
Engineering	AEP Project	(150,000)	(150,000)	(150,000)	(150,000)	(600,000)	(697,219)
Engineering Total		**(330,000)**	**(330,000)**	**(330,000)**	**(330,000)**	**(1,320,000)**	**(1,319,708)**
Operations	Operating Reserve Sharing	-	-	-	-	-	(64,000)
Operations Total		**-**	**-**	**-**	**-**	**-**	**(64,000)**
Grand Total		**(732,000)**	**(340,000)**	**(330,000)**	**(330,000)**	**(1,732,000)**	**(2,354,927)**

Capital Expenditures
2004 Budget

Project	Department	Subaccount	January	February	March	April	May	June	July	August	September	October	November	December	2004 Budget	2003 Estimate *
Disaster Recovery Site Total			116,125	35,000	153,000	-	-	765,000	-	-	-	-	-	-	1,069,125	405,854
Maintenance - Hardware Total			477,214	209,000	43,238	37,000	14,000	24,438	33,000	17,000	-	8,000	3,000	-	865,890	296,959
Maintenance - Servers Total			76,940	36,000	15,000	7,500	-	22,500	44,500	27,000	-	-	-	-	229,440	134,416
Maintenance - Software Total			428,715	5,725	187,175	92,350	3,000	-	3,600	8,284	2,500	2,400	-	19,000	752,749	276,898
Maintenance - Routers & Switches Total			12,400	173,300	-	12,400	15,500	-	-	15,500	-	-	15,500	-	244,600	207,812
Market Project Total			1,330,260	633,000	593,000	643,000	643,000	667,195	1,443,000	1,443,000	1,443,000	1,443,000	1,443,000	863,000	12,587,455	470,000
OASIS AFC Granularity Total			140,000	-	-	-	-	-	-	-	-	-	-	-	140,000	-
Grand Total			2,581,654	1,092,025	991,413	792,250	675,500	1,479,133	1,524,100	1,510,784	1,445,500	1,453,400	1,461,500	882,000	15,889,259	1,791,939

Capital Expenditures	January	February	March	April	May	June	July	August	September	October	November	December	Total
2001 Actual	651,094	15,543	(107,716)	93,926	(447,334)	102,521	107,021	80,310	113,385	67,172	50,455	114,157	840,535
2002 Actual	49,081	11,962	18,948	20,401	36,106	66,788	59,973	13,706	15,223	53,946	15,831	46,979	408,944
2003 Estimate *	155,016	4,976	21,683	20,387	8,868	25,748	970,825	70,025	121,025	274,025	60,025	83,025	1,815,628

* contains actual for January - June, and budget for July - December

Debt Payments
2004 Budget

Department	Group	Account	January	February	March	April	May	June	July	August	September	October	November	December	2004 Total	2003 Estimate *
Administration	Administration	Payment on Note - Interest	-	-	937,500	-	-	-	-	-	750,000	-	-	-	1,687,500	1,875,000
Administration	Administration	Payment on Note - Principal	-	-	5,000,000	-	-	-	-	-	-	-	-	-	5,000,000	-
Administration	Administration	Payment on Line of Credit - Interest	7,500	2,500	27,500	25,000	20,000	17,500	12,750	7,500	7,500	5,000	-	-	132,750	-
Administration	Administration	Payment on 2004 Capital Expenditures - Interest	12,908	18,368	23,325	27,287	30,664	38,060	45,680	53,234	60,462	67,729	75,036	79,446	532,199	-
Administration Total			20,408	20,868	5,988,325	52,287	50,664	55,560	58,430	60,734	817,962	72,729	75,036	79,446	7,352,449	1,875,000
Grand Total			20,408	20,868	5,988,325	52,287	50,664	55,560	58,430	60,734	817,962	72,729	75,036	79,446	7,352,449	1,875,000

Revenue
2004 Budget

Item	January	February	March	April	May	June	July	August	September	October	November	December	2004 Total
Member Fee Total	1,144,951	-	-	-	-	-	-	-	-	-	-	-	1,144,951
NERC Fee Total	200,007	-	-	200,007	-	-	200,007	-	-	200,007	-	-	800,028
Assessment Total	3,095,701	2,824,710	3,130,017	3,028,577	3,120,178	3,026,292	3,133,252	3,129,983	3,033,182	3,142,154	3,025,278	3,146,319	36,835,643
Grand Total	4,440,659	2,824,710	3,130,017	3,228,584	3,120,178	3,026,292	3,333,259	3,129,983	3,033,182	3,342,161	3,025,278	3,146,319	38,780,622

MINUTES NO. 35

Southwest Power Pool
MEETING OF MEMBERS
Le Meridien Hotel – New Orleans, Lousiana
November 13, 2002

Agenda Item 1 – Administrative Items
SPP Board of Directors Chair, Mr. Al Strecker, called the meeting to order at 8:28 a.m. (Agenda Attachment 1). Since there were no additional attendees from yesterday's meeting, introductions were dispensed (Attendance List – Attachment 2). There were 28 people in attendance representing 19 members. The secretary received 4 proxy statements (Proxies – Attachment 3). Mr. Strecker asked if there were any necessary corrections to the minutes of December 12, 2001 (12/12/02 Minutes – Attachment 4).

Agenda Item 2 – President's Report
Mr. Strecker asked Mr. John Marschewski for a report on SPP activities (President's Report – Attachment 5). Mr. Marschewski reported on the budget, membership, staffing and gave a brief merger update.

Agenda Item 3 – 2002 Organization Overview/2003 Outlook
Mr. Nick Brown gave the organizational overview for 2002 and outlook for 2003 (2002 Organizational Overview/2003 Outlook – Attachment 6). Mr. Brown reviewed current challenges facing staff with regard to merger issues. He also looked ahead to initiatives to improve current tariff/operations/planning; complete MISO merger and integration; complete RRO merger and to implementing energy market, joint market with PJM and seams management with neighbors.

Agenda Item 4 – 2002 Operation Overview/2003 Outlook
Mr. Carl Monroe gave the operational overview for 2002 and outlook for 2003 (2002 Operational Overview/2003 Outlook – Attachment 7).

Agenda Item 5 – Financial Overview/2003 Outlook
Mr. Tom Dunn presented the Financial Overview and 2003 Outlook (2002 Financial Overview/2003 Outlook – Attachment 8).

Agenda Item 7 – Nominating Task Force
Mr. Christiano referred to the current board roster (NTF Report – Attachment 10). The Nominating Task Force nominated the five persons with expiring terms for consideration of the membership for the 2005 class of the SPP Board of Directors. These nominations are shown on the election ballot (Ballot – Attachment 11). The Nominating Task Force also recommended that the membership leave open the three vacant positions on the current Board of Directors due to the pending merger between SPP and the Midwest ISO. Ms. Harper had expressed concern in leaving the current vacant positions open in that there would be an imbalance of users to owners represented. It was agreed upon at the Board of Directors meeting that Staff would contact individuals and provide recommendations to the Board of Directors to consider in filling those vacant positions. Mr. Strecker called attention to the ballot of nominations as presented from the Nominating Task Force and opened the floor for additional nominees. Hearing no additional nominees, Mr. Strecker closed the nomination process and asked each member to mark their ballots. The ballots were collected and votes counted. Mr. Brown reported that nominees had been unanimously elected and the ballots will be kept on file at the SPP office.

Agenda Item 6 – NERC Board of Trustees Report
Mr. Marschewski presented the NERC Board of Trustees Report (Board of Trustees Meeting Highlights – Attachment 11).

Respectfully Submitted,
Nicholas A. Brown, Corporate Secretary

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

October 10, 2003

To: **NERC Control Areas and Reliability Coordinators**

Subject: **Near-Term Actions to Assure Reliable Operations**

The NERC Board of Trustees, with the endorsement of its Stakeholders Committee, directed on October 10, 2003 that the following letter be sent to the CEOs of all NERC Control Areas and Reliability Coordinators.

NERC is assisting the United States-Canada Power Outage Task Force's joint-international investigation of the August 14 blackout that affected parts of the Midwest and Northeast United States, and Ontario, Canada. Although considerable progress has been made in the investigation to determine what happened, an understanding of the causes of the outage is still being developed through analysis by teams of experts.

The reliability of the North American bulk electric systems, including the avoidance of future cascading outages, is of paramount importance to NERC and its stakeholders. Pending the outcome of the final report on the outage, NERC emphasizes to all entities responsible for the reliable operation of bulk electric systems the importance of assuring those systems are operated within their design criteria and within conditions known to be reliable through analytic study. If the power system enters an unanalyzed state, system operators must have the authority and the capability to take emergency actions to return the power system to a safe condition.

NERC requests that each entity in North America that operates a Control Area and each NERC Reliability Coordinator review the following list of reliability practices to ensure their organizations are within NERC and regional reliability council standards and established good utility practices. NERC further requests that within 60 days, each entity report in writing to their respective regional reliability council, with a copy to NERC, that such a review has been completed and the status of any necessary corrective actions. This brief list of near-term actions is not in any way intended to diminish the need to comply with all NERC and regional reliability council standards and good utility practices.

1. **Voltage and Reactive Management:** Ensure sufficient voltage support for reliable operations.
    - Establish a daily voltage/reactive management plan, assuring an adequate static and dynamic reactive supply under a credible range of system dispatch patterns.
    - During anticipated heavy load days, or conditions of system stress such as caused by heavy wide-area transfers, ensure all possible VAR supplies are verified and available, and VAR supplies are applied early in the day ahead of load pickup.
    - Reserve sufficient dynamic reactive supply (e.g. online generation and other dynamic VAR resources) to meet regional operating criteria and system needs.
    - In accordance with NERC and regional practices maintain voltage schedules of all bulk electric transmission facilities above 95% nominal values <u>and</u> in conformance with regional criteria.

- Report any low voltage limit violations at critical high voltage transmission facilities to the reliability coordinator.
- Ensure all interconnected generators that have, or are required to have, automatic voltage regulation (AVR) are operating under AVR.
- Coordinate potential differences of voltage criteria and schedules between systems and ensure these differences are factored into daily operations.

2. **Reliability Communications:** Review, and as necessary strengthen, communication protocols between Control Area operators, Reliability Coordinators, and ISOs.
   - Share the status of key facilities with other appropriate Control Area operators, Reliability Coordinators, and ISOs.
   - Control Area operators, Reliability Coordinators, and ISOs should conduct periodic conference calls to discuss expected system conditions and notify all neighboring systems of any unusual conditions. Conduct additional calls as needed for system critical days.

3. **Failures of System Monitoring and Control Functions:** Review and as necessary, establish a formal means to immediately notify control room personnel when SCADA or EMS functions, that are critical to reliability, have failed and when they are restored.
   - Establish an automated method to alert power system operators and technical support personnel when power system status indications are not current, or that alarms are not being received or annunciated.
   - Determine what backup capabilities can be utilized when primary alarm systems are unavailable. If a backup to failed alarms is not immediately available, then monitoring and control should be transferred in accordance with approved backup plans.
   - Identify and implement procedures to move to 'conservative system operations' when operators are unsure about next contingency outcomes (i.e., unstudied conditions, loss of SCADA or EMS visibility, unexplained or unknown power system conditions).
   - Ensure all critical computer and communication systems have a backup power supply, and the backup supply is periodically tested.
   - Ensure that system operators have a clear understanding of the impact to their energy management system control functions whenever their transaction tagging and scheduling systems fail. Identify and implement appropriate contingency procedures for loss of real-time ACE and AGC control.

4. **Emergency Action Plans:** Ensure that emergency action plans and procedures are in place to safeguard the system under emergency conditions by defining actions operators may take to arrest disturbances and prevent cascading.
   - Actions might include but should not be limited to acting immediately to reduce transmission loading, ordering redispatch, requiring maximum reactive output from interconnected resources, and shedding load without first implementing normal operating procedures.
   - Ensure operators know, not only that they have the authority to shed load under emergencies, but that, in addition, they are expected to exercise that authority to prevent cascading.

5. **Training for Emergencies:** Ensure that all operating staff are trained and certified, if required, and practice emergency drills that include criteria for declaring an emergency, prioritized action plans, staffing and responsibilities, and communications.

6. **Vegetation Management:** Ensure high voltage transmission line rights of way are free of vegetation and other obstructions that could contact an energized conductor within the normal and emergency ratings of each line.

Michehl R. Gent
President and CEO

Southwest Power Pool
NOMINATING TASK FORCE
Report to the Membership
October 29, 2003

Current Board of Directors Roster

The current SPP Board of Directors roster with terms is as follows:

Transmission Owners (Bylaws require 7)
- IOU
  - Dick Dixon (Westar) – 1 year
  - Richard Verret (AEP) – 1 year
  - Al Strecker (OKGE) – 2 year
  - Richard Spring (KCPL) – 3 year
- Non-IOU (Bylaws require at least 2)
  - Open – 2 year
  - Gene Argo (MIDW) – 2 year
  - Mike Deihl (SWPA) – 3 year

Transmission Users (Bylaws require 7)
- Cooperative (Bylaws require 2)
  - Gary Voigt (AREC) – 1 year
  - Stephen Parr (Kepco) – 2 year
- Municipal (Bylaws require 2)
  - Harry Dawson (OMPA) – 1 year
  - David Christiano (SPRM) – 3 year
- IPP/Marketer/Other (Bylaws require 3)
  - Trudy Harper (Tenaska) – 2 year
  - Michael Gildea (Duke) – 3 year
  - Walt Yeager (Cinergy) – 3 year

Non-stakeholders (Bylaws require 7)
- Vacant – 3 year
- Tom McDaniel – 3 year
- Jim Eckelberger – 2 year
- Quentin Jackson – 3 year
- Harry Skilton – 1 year
- Larry Sur – 1 year
- John Marschewski - President

Background

Members of the SPP Board of Directors serve staggered three-year terms with six or seven terms expiring each year. The following directors have terms expiring this calendar year:

Transmission Owners

IOU

Dick Dixon (Westar)
Richard Verret (AEP)

Transmission Users

Cooperative

Gary Voigt (AREC)

Municipal

Harry Dawson (OMPA)

Non-Stakeholder

Harry Skilton
Larry Sur

Additionally, Larry Sur asked not to be re-nominated and Tom McDaniel is resigning, both due to time constraints, which vacates non-stakeholder positions with a three-year term and a two-year term going forward. Gary Roulet was elected by the Board of Directors to fill the unexpired term of J. M. Shafer on an interim basis until the next meeting of the membership.

Per SPP's Bylaws, the Nominating Task Force is responsible for nominating to the membership candidates equal in number to the board positions to be filled (positions with expiring terms, any vacancies and temporary appointments) and for nominating to the Board of Directors a chair and vice-chair for two-year terms. Transmission Owners are to nominate Owners, Transmission Users are to nominate Users and all representatives on the Nominating Task Force are to nominate the non-stakeholders. The Nominating Task Force consists of David Christiano (Chair), Gary Voigt, Stephen Parr, Michael Deihl, Dick Dixon, and Al Strecker.

The Nominating Task Force engaged Larry Klock of the independent search firm Russell Reynolds Associates to assist them in filling the non-stakeholder director positions. More than twenty candidates were originally considered of which seven were personally interviewed by the Nominating Task Force.

Nominees

The Nominating Task Force nominates to the membership for their expiring terms: Dick Dixon, Richard Verret, Gary Voigt, Harry Dawson, and Harry Skilton; and that Gary Roulet be nominated to the membership to fill the unexpired terms of J. M. Shafer. The

Nominating Task Force also nominates to the membership Robert Schoenberger to fill the vacant director position, Joshua Martin to fill the expiring term of Larry Sur, and Phyllis Bernard to fill the unexpired term of Tom McDaniel. These nominations are show on the attached election ballot.

Non-Stakeholder Director Nominee Biographical Information

Phyllis E. Bernard
Robert S. Kerr Jr. Distinguished Professor of Law
Director of the Center on Alternative Dispute Resolution
Oklahoma City University School of Law

Professor Bernard is a frequent lecturer and presenter at academic and professional conferences throughout the nation. Professor Bernard's research and teaching interests in mediation derive from practical experience as a litigator, lobbyist and adjudicator in Washington, D.C. during the 1980s. Her scholarly work focuses on system design, ethics and cultural dynamics in dispute resolution. On the international level, Professor Bernard has served as a consultant to the U.N. World Health Organization, advising the Lao People's Democratic Republic on privatization of the health care system and development of a quality of care dispute resolution system. Professor Bernard has begun a continuing *pro bono* consultation with the International Federation of Women Lawyers in the Niger Delta, where she was asked to design an appropriate tribal peacemaking program, using the **Early Settlement** model. In the American Bar Association, Professor Bernard has served on the governing council of two sections: the Section of Administrative Law and Regulatory Practice and the Dispute Resolution Section. She is Dispute Resolution Section Liaison to the ABA Africa Law Initiative. Professor Bernard holds an A.B. degree from Bryn Mawr College, an M.A. from Columbia University, and a J.D. from the University of Pennsylvania.

Robert G. Schoenberger
Chairman, CEO and President
Unitil Corporation

Mr. Schoenberger joined Unitil Corporation as Chairman and Chief Executive Officer in 1997. In addition to operation of its utility companies, Unitil is emerging as a leader in the business to business e-commerce sector of the energy industry via its Usource subsidiary and investment in Enermetrix.com. Mr. Schoenberger began his career in 1974 working for the New York State Division of the Budget and the Governor's office. He later joined the New York Power Authority (NYPA) and served in a variety of executive positions, including CFO and President and COO. Among his achievements were the successful restructuring of NYPA's nuclear operations and the significant improvement of its customer focus. Mr. Schoenberger received his BA from LaSalle University, his Masters Degree in History from the University of Delaware and completed the Advanced Management Program at the Harvard Business School.

Joshua W. Martin, III
President
Verizon Delaware Inc.

Mr. Martin oversees all aspects of Verizon's telecommunications business within Delaware. Mr. Martin first joined the company as Vice President, General Counsel and Secretary on January 2, 1990. Prior to joining Verizon, Mr. Martin was a Delaware Superior Court Judge for eight years. Earlier, he served on the Delaware Public Service Commission from 1978 to 1982, including three years as Chairman. After obtaining his law degree, Mr. Martin joined Hercules, Inc., where he was a Patent Attorney until 1982. Mr. Martin began his professional career as a Physicist at DuPont Company in 1966. Mr. Marin is a leader in education as well as professional and community organizations. He holds honorary degrees from Widener University and Goldey Beacom College. He was nominated as Delawarean of the Century, in business, by Wilmington News Journal in November, 1999. He received the Arthur E. Armitage Sr., Distinguished Alumni Award from Rutgers School of Law in 1998 for service to the community and contributions to the legal profession. Born and raised in Columbia, S. Carolina, Mr. Martin holds a bachelor's degree in physics from Case Institute of Technology, is a graduate of the Rutgers University School of Law and completed the Wharton School Executive Development Program in l996. Mr. Martin and his wife Cynthia reside in Hockessin, Delaware.

Approved: Nominating Task Force September 23 & October 7, 2003

Action Requested: Elect Nominees

Southwest Power Pool
ANNUAL MEETING OF MEMBERS
October 29, 2003

Ballot for
Board of Directors

Each Transmission Owning Member should vote for 3 nominees:

Recommended by Nominating Task Force:
- ☐ Dick Dixon (Westar, three year term)
- ☐ Richard Verret (AEP, three year term)
- ☐ Gary Roulet (WEFA, two year term)

Additional Nominees:
- ☐ ________________________________
- ☐ ________________________________

Each Transmission Using Member should vote for 2 nominees:

Recommended by Nominating Task Force:
- ☐ Gary Voigt (AREC, three year term)
- ☐ Harry Dawson (OMPA, three year term)

Additional Nominees:
- ☐ ________________________________
- ☐ ________________________________

Each Member should vote for 4 Non-Stakeholder nominees:

Recommended by Nominating Task Force:
- ☐ Harry Skilton (Re-election, three year term)
- ☐ Joshua W. Martin, III (expiring term of Larry Sur, three year term)
- ☐ Phyllis E. Bernard (unexpired term of Tom McDaniel, two year term)
- ☐ Robert G. Schoenberger (vacant position, two year term)

Additional Nominees:
- ☐ ________________________________
- ☐ ________________________________

MEMBER: ______________________________

REPRESENTATIVE'S SIGNATURE: ______________________________

Southwest Power Pool
NOMINATING TASK FORCE
Report to the Board of Directors
October 29, 2003

Background

Per SPP's Bylaws, the Board of Directors is to elect from its membership a Chair and Vice Chair to serve two-year terms. The terms of Chair Al Strecker and Vice Chair Jim Eckelberger are expiring this month. The Nominating Task Force has been responsible for nominating candidates to the Board of Directors for these positions. The Nominating Task Force consists of David Christiano (Chair), Gary Voigt, Stephen Parr, Michael Deihl, Dick Dixon, and Al Strecker. At its August 26, 2003 meeting, the Board of Directors elected non-stakeholder director Jim Eckelberger to fill the unexpired Vice Chair term vacated by J. M. Shafer.

In its deliberations, the Nominating Task Force considered the transition to a complete non-stakeholder board as proposed in SPP's RTO application filed with the FERC on October 15, 2003. This transition is to occur on or before the first of the month between the thirtieth and sixtieth day following a final FERC order on the application. SPP is proposing that the current non-stakeholder sector become the new Board of Directors. Given the expectation of a favorable FERC order on SPP's RTO application, the Nominating Task Force believes stability in leadership during this transition period is both beneficial and necessary, and that the new Board of Directors should follow the processes in the bylaws filed with the RTO application to elect its Chair and Vice Chair upon transition.

The Nominating Task Force also reviewed SPP's fee schedule for compensation of non-stakeholder directors, which has been in place since 1999 without change. Based on this review, the group is recommending modification.

Nominees

The Nominating Task Force nominates to the Board of Directors Al Strecker to serve as Chair and Jim Eckelberger to serve as Vice Chair, for two-year terms, or until transition to the governance structure in SPP's RTO application.

Recommendation

The Nominating Task Force recommends to the Board of Director the following fee schedule for the compensation of non-stakeholder directors:

Annual Retainer - $15,000 (no change)
Board Meeting Director Attendance Fee - $3000 (no change)
Board Meeting Chair Attendance Fee - $3500 (currently $3000)
Board Meeting Director Teleconference Fee - $500 (currently $1500)
Committee Meeting Attendance Fee - $2000 (currently none)
Committee Meeting Chair Fee - $2500 (currently none)
Committee Meeting Teleconference Fee - $500 (currently none)

Approved: Nominating Task Force September 23 & October 7, 2003

Action Requested: Elect Nominees and Approve Recommendation