Hello!

Enclosed is an agenda and background materials for our upcoming SPP Board of Directors Meeting October 17 at DFW Airport Hyatt, Dallas, Texas in the Nova Room from 8:00 a.m. until 2:00 p.m. The Directors will meet in Executive Session from 8:00 a.m. until 10:00 a.m.

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

Take Care,

NAB:cr
Enclosure
Cc: SPP Membership (via email)
Southwest Power Pool
BOARD OF DIRECTORS MEETING
Wednesday, October 17, 2001
Hyatt Hotel – Dallas/Ft. Worth Airport
Nova Room – East Tower

- A G E N D A -

8 a.m. – 10 a.m. – Executive Session

2. SPP/MISO Governance Group Report...............................................Harry Skilton

10:00 a.m. – Open Session

3. Approval of August 13, 2001 Meeting Minutes.................................Gary Voigt
4. SPP/MISO Merger..............................................................................John Marschewski
5. Engineering & Operating Committee Report....................................Mel Perkins
   a. Criteria Recommendations

2 p.m. – Adjournment
1. Approved minutes of the July 17, 2001 Board of Directors meeting as presented.

2. Approved good faith negotiation with the Midwest ISO based on a proposed merger term sheet but with equity in governance.

3. Directed Staff to collect member comments on draft merger term sheet, analyze, and report to Board of Directors by end of September 2001.
Agenda Item 1 - Administrative Items
SPP Chair Mr. Gary Voigt called the meeting to order at 11:03 a.m. The following directors were in attendance or represented by proxy:

- Mr. Gene Argo, Midwest Energy, Inc.;
- Ms. Betsy Carr, proxy for Ms. Kim Casey, Dynegy Marketing and Trade;
- Mr. David Christiano, City Utilities of Springfield, MO;
- Mr. Harry Dawson, OK Municipal Power Authority;
- Mr. Michael Deihl, Southwestern Power Administration;
- Mr. Jim Eckelberger, non-stakeholder director;
- Mr. Tom Grennan, Western Resources;
- Ms. Trudy Harper, Tenaska Power Services;
- Mr. John Marschewski, Southwest Power Pool, Inc.;
- Mr. Tom McDaniel, non-stakeholder director;
- Mr. John Oxendine, non-stakeholder director;
- Mr. Stephen Parr, KS Electric Power Cooperative;
- Mr. J. M. Shafer, Western Farmers Electric Cooperative;
- Mr. Harry Skilton, and proxy for Mr. Quentin Jackson, non-stakeholder directors;
- Mr. Richard Spring, Kansas City Power & Light;
- Mr. Al Strecker, OG+E;
- Mr. Larry Sur, non-stakeholder director;
- Mr. Richard Verret, American Electric Power; and
- Mr. Gary Voigt, Chair, Arkansas Electric Cooperative Corp.

There were 49 persons in attendance representing 26 members, 1 guest and 3 regulatory agencies (Attendance List – Attachment 1). The Secretary received 2 proxy statements (Proxies – Attachment 2). Mr. Voigt referred to the brief but significant agenda (Agenda – Attachment 3) and asked for any modifications to draft minutes of the July 17, 2001 meeting or a motion for approval (7/17/01 Meeting Minutes – Attachment 4). Mr. Shafer moved that the minutes be approved as presented. Mr. Deihl seconded this motion, which passed unopposed.

Agenda Item 2 – Secretary’s Report
Mr. Voigt called on Mr. Nick Brown (SPP) to give the Secretary’s Report. Mr. Brown informed the Board of Directors of current SPP activities, including: southeast RTO mediation proceedings, rehearing requests on SPP dockets, and the market settlement project. Mr. Brown stated that SPP and many member representatives have been involved in FERC’s southeast RTO mediation process in Washington D.C. Mr. Brown stated that these meetings are subject to confidentiality requirements set forth in Rule 606 of the Commission’s Rules of Practice and Procedure and that information cannot be disclosed without permission of all participants. Due to this gag order, Mr. Brown
SPP Board of Directors Minutes
August 13, 2001

asked that those not a party to the related dockets please leave the room. He then explained the mediation process and actions to date.

Mr. Brown informed the Board of Directors that a rehearing request as per direction at the July 17, 2001 meeting had been filed August 8, 2001 (Request for Rehearing – Attachment 5) with a request to expedite the hearing. He then pointed out key issues in the request as:

- Decision contradicts previous direction to SPP;
- Decision does not follow Commission precedent regarding RTOs; and
- Decision represents a policy change without following administrative law procedures.

SPP’s General Counsel, Mr. Mike Small (Wright and Talisman), was present to make comments and answer questions.

Mr. Brown concluded his report by giving a status report on the market settlement project stating it was on schedule for December 15, 2001 and the integration test has commenced. There have been 19 change orders to date, 6 being with minimal cost impact. A full report is available at www.spp.org.

**Agenda Item 3 – Southwest Power Pool/Midwest ISO Merger**

Mr. John Marschewski informed the Board of Directors of activities in parallel to the southeast mediation proceedings occurring with MISO concerning a SPP/MISO merger. After Mr. Marschewski visited with SPP chair and vice-chair as well as non-stakeholder directors, Mr. Marschewski, Mr. Jim Torgerson (MISO CEO) and Mr. Mike Small crafted the term sheet distributed to the Board with the meeting background materials (Term Sheet – Attachment 6). Mr. Marschewski stated that both organizations had similar RTO models, systems and tariffs, and both lack scope and configuration to meet FERC’s current expectations. Mr. Marschewski noted that the biggest challenge concerns equity in governance and much discussion ensued on this topic.

Mr. Harry Dawson moved to accept the general terms sheet as proposed with inclusion of two-thirds majority vote for action of new board of directors, and with comments from members due in one week for inclusion in negotiating final documents. Mr. John Oxendine seconded this motion, which failed with 10 votes for and 7 opposed. Following additional discussion, Ms. Trudy Harper moved to continue good faith negotiation to definitive terms based on this terms sheet as a basis for agreement until the end of September; without agreement, SPP would request that FERC order mediation between SPP and MISO - again, with comments from members due in one week for inclusion in negotiating final documents. Mr. Steve Parr seconded this motion. After lengthy discussion, the motion failed with 9 votes for and 9 opposed.

Following a short break, Mr. Jim Eckelberger moved that the Board authorize the continued good faith negotiation with MISO based on the proposed term sheet but with equity in governance and that the resulting due diligence review and the best possible terms be offered to the Board of Directors for approval by the end of September. Mr. Richard Verret seconded this motion, which passed unopposed. Mr. Eckelberger
further moved that in the event that negotiation is unsuccessful, the Board would anticipate that SPP ask FERC to order mediation at the end of September. Mr. Harry Dawson seconded this motion, which failed with 5 votes for and 12 opposed. Mr. Voigt encouraged everyone to submit comments to Staff within the next week and directed Staff to collect, analyze for conflict, and where possible to resolve issues. A next meeting of the Board of Directors was contemplated in the first half of September.

Several directors asked that Staff continue to consider other options.

Adjournment
At 2:40 p.m., Mr. Voigt thanked everyone for their participation and following a short break, reconvened in executive session to discuss personnel matters.

Nicholas A. Brown, Corporate Secretary
MEMORANDUM

TO:        SPP Board of Directors
          MISO Board of Directors

FROM:     John Marschewski
          President, SPP

          Jim Torgerson
          President and CEO, MISO

DATE:     October 10, 2001

SUBJECT: Combination of MISO and SPP

This memorandum summarizes the discussions between MISO and SPP on structuring the proposed combination of the two organizations, and describes the approach that MISO and SPP management recommend to their respective Boards of Directors. In reaching consensus on the transaction’s structure, management started from the premise that the legal method chosen for combining the organizations would not influence or determine the important issues – principally governance, financial strength and management of the combined entity – that are being dealt with by subcommittees of the two Boards, and that therefore the choice of a transaction structure should be based on practical considerations. The most important of those considerations are:

• preserving a 501(c)(4) tax-exempt status for the new entity, as that appears to be the most appropriate designation in light of the nature of the new entity’s membership and expected operations;
• separating SPP’s reliability council functions from the new entity, at least at the outset; and

• minimizing the costs and operational difficulties of combining MISO and SPP, and otherwise using a structure that will carry out the transaction most efficiently.

Management considered three alternative structures: (1) a merger of MISO or SPP into the other party, (2) a consolidation of MISO and SPP into a newly formed entity, or (3) the acquisition by one party of the other’s assets and the assumption of its liabilities. Counsel for both parties recommended the third alternative as best addressing the practical considerations that the parties had identified. MISO and SPP management concur in that assessment, and recommend the following:

• The transaction should be structured as a purchase and assumption whereby SPP will, except as set forth below, transfer substantially all of its assets and liabilities to MISO. The choice of MISO as the acquiring entity is based primarily on the fact that it already holds the desired 501(c)(4) tax-exempt designation, while SPP holds a 501(c)(6) designation.

• In conjunction with the transfer of assets, MISO’s governance and management functions, and its membership agreement, will be reconfigured to meet the requirements set by the MISO and SPP Boards. The reconfigured MISO will change its name to one agreed upon by the parties. For convenience in the remainder of this memorandum, the reconfigured MISO will be referred to as “Newco.”

• The only assets and liabilities of SPP that will not be transferred to Newco will be those, such as they may be, constituting SPP’s reliability council functions. The reliability council functions will remain with SPP, which will operate under its
existing (or a revised) charter and with its own board of directors, but which will contract with Newco for necessary management and operational functions. Newco will be obligated to provide those functions at cost. The relationship between Newco and the reliability council company may be modified in the future if it is deemed to be appropriate.

- Included in the transfer will be the administrative responsibility of Newco to reimburse, through tariff collections or otherwise, current SPP members for costs incurred by them up to the closing date of this transaction for shortfalls of SPP tariff income (a regulatory true-up) as currently conducted by SPP.

- The current Appendix I of MISO’s membership agreement, the proposed Entergy MOU with SPP, or an appropriate substitute to accommodate the business needs of Transcos or ITCs would be available to forming Transcos or ITCs.

If the MISO and SPP Boards accept the recommended structure, the senior management teams and their respective counsel will prepare the documents necessary to complete the combination. The primary documents will be a Purchase and Assumption Agreement setting forth in detail the terms and conditions of the transaction, bylaws for Newco implementing the agreed-upon governance structure, and a revised membership agreement that blends together in a mutually acceptable manner the substantive provisions of both MISO’s and SPP’s membership agreements.

Based on discussions to date, following are some of the key areas that will be covered in the Purchase and Assumption Agreement:

- The employee benefits to be provided by Newco shall, in the aggregate, be comparable in value to the benefits currently enjoyed by the employees of MISO and
SPP. Further, the combined benefit program will be sensitive to late-career employees (to be defined as either those who are within 10 years of their earliest retirement age or those who are within 15 years of their normal retirement age) and will not result in intentional reductions of employee retirement benefits to existing employees that meet this definition.

• The Purchase and Assumption Agreement will include the following conditions to closing, among others: (1) a FERC order allowing for the charge of an administrative fee on all load in Newco’s footprint, or a member assessment to cover Newco’s operating costs (MISO docket re: fee is currently pending at FERC); (2) SPP members constituting substantially all of SPP’s load executing the Newco membership agreement; (3) MISO members constituting substantially all of MISO’s load executing the Newco membership agreement or any required amendments of the existing MISO membership agreement; (4) MISO’s membership agreement and bylaws being amended to the parties’ mutual satisfaction; and (5) the receipt of necessary regulatory and third-party consents, waivers and approvals.

Both MISO and SPP management are highly motivated to proceed with the proposed transaction and believe it to be in their respective members’ best interests. The SPP Board of Directors, at the October 17 meeting, and the MISO Board of Directors, at the October 18 meeting, will be asked to grant their respective management teams the authority to prepare the documents needed to effect the transaction. The transaction will require the final approval of both SPP’s and MISO’s Boards of Directors and their members, which will be requested at regular or special meetings to be scheduled after the proposed Purchase and Assumption Agreement and other transaction documents have been reviewed by the Boards.
Southwest Power Pool  
Board of Directors Meeting  
September 20, 2001  

Staff Report – SPP/Midwest ISO Merger

Background
On July 12, 2001 the Federal Energy Regulatory Commission (FERC) issued two orders specifically related to SPP: RTO1-100 order initiating Southeast mediation and RTO1-34 order rejecting SPP’s RTO filings. SPP was ordered into mediation for 45 days beginning July 17, 2001 with the goal of establishing a single Southeastern RTO. At its July 13 meeting, the SPP Board of Directors agreed to a two-fold response plan: 1) to seek rehearing of the order in RT01-34 for the purpose of protecting legal rights, and 2) to pursue the formation of a super-regional RTO including both the Midwest and the Southeast and that this idea be pursued in parallel fashion in the Southeast mediation and separately with entities in the Midwest.

At its August 13 meeting, SPP President John Marschewski presented a draft term sheet detailing a potential merger between SPP and the Midwest ISO for consideration of the Board of Directors. The draft term sheet was the product of initial discussions between presidents of the two organizations and detailed the formation of a new corporation from the combined assets of SPP and MISO. The Board of Directors authorized the continued good faith negotiation with MISO based on the proposed term sheet but with equity in governance, and that the resulting due diligence review and the best possible terms be offered to the Board of Directors for further consideration by the end of September. The Board of Directors also solicited comments from members on the draft term sheet, and directed Staff to collect, analyze for conflict, and where possible to resolve and respond to the issues.

Response to Member Comments on Draft SPP/MISO Merger Term Sheet
To date, Staff has collected, summarized, and responded to comments from members as shown in the attached document (Comments & Responses – Attachment 1) and has begun due diligence analysis of the merger. SPP member comments were primarily focused on: 1) the desire for more detail on the new company, tariff transition issues, and member obligations; 2) the business rationale for the merger and specific draft terms; and 3) evaluation of other alternatives.

Some members commented that teams of members should be used in the development of definitive documents, including the tariff. To date, the Board has directed SPP Staff to develop definitive documents for Board consideration taking into account all member issues.

Most members simply want more information than was provided in the initial draft term sheet. SPP and MISO Staffs are in the process of exchanging information, documents, contracts, bylaws, etc. that are going through a legal, business, and financial review to
provide more information regarding the combination. This will result in the definitive
documents referenced in the last part of the draft term sheet to create bylaws for the
new corporation, membership agreements, operating policies, articles of incorporation,
etc. Functions of the new company, staffing (including incentives), and systems
(including for-profit subs) will be explained, including the provision of services outside
the new organization footprint to customers under contract. Staff anticipates that any
resulting organization will take the best of each organization, including possibly the
stakeholder input model (sectors, balanced sectors, etc.). Currently, MISO has no
regional reliability functions and no provision to assume these functions. Cost
separation of the regional reliability functions is being determined as NERC regions and
their members continue to determine their boundaries. Within current boundaries of
SPP and MISO, Entergy is in the SERC reliability region and MISO members are in
MAPP, MAIN, ECAR, and SPP.

Several members questioned how the financial analysis of the merger would be
performed. In addition to other liabilities, the due diligence analysis includes the
obligation SPP has to its members for expenses incurred as residual costs not covered
by SPP’s administration fee paid by tariff customers. Under MISO agreements, non-
transmission owning members pay an additional cost that would need to be considered
in the consolidation documents. This provision will be revisited.

Some members questioned the allocation of Staff resources to seeking rehearing of
FERC’s July 12, 2001 order rather than focusing solely on the merger and the future.
SPP’s request for rehearing (filed August 8, 2001) was per instruction of the Board of
Directors to protect SPP’s legal rights, particularly in the area of cost recovery for
expenses incurred at FERC’s encouragement. No additional SPP Staff activity is
anticipated on the rehearing request pending FERC action and subsequent Board of
Directors action. FERC did grant rehearing in an order issued August 27, 2001 for the
limited purpose of further consideration, but it is doubtful that any procedural meetings
will be scheduled in the near future. Absent timely processes, SPP could seek an order
from the U.S. Court of Appeals directing the FERC to take action.

Several members question the maintenance of two tariffs. The purpose of this term
sheet provision is to allow for a smooth transition from two tariffs (one operational) to
one tariff. The expectation is that the combination and resulting benefits can be
achieved faster than the negotiation and acceptance (including FERC’s) of a single
tariff. The new company will have exclusive right to modify each of the existing tariffs.
Some terms and conditions and most business practices will have to be standardized
quickly to eliminate rate pancaking using a mechanism like the MISO/ARTO settlement
agreement to ensure recovery of revenue requirements.

Some members stated a desire to be released from membership obligations based on
FERC’s July 12, 2001 order. SPP member obligations are limited and governed by the
membership agreement and bylaws. The July 12 order did nothing to change the
current relationship between SPP and its members and customers as described in
SPP’s membership agreement, bylaws and/or tariff and, as stated above, FERC has
granted rehearing of that order. Also, the recently approved financing agreement for
market settlement systems place certain conditions on the Board of Director’s ability to
modify member obligations.

Evaluation of Options to SPP/MISO Merger
At this point, Staff has no indication as to what FERC will do in the Midwest. However,
the Board of Directors instructed Staff to explore Midwest options in parallel with the
southeast mediation, as well as a super-regional RTO.

Southeast
The primary issue is what is best for SPP members. SPP participated as ordered in the
southeast mediation and the administrative law judge filed a report with the FERC on
September 10, 2001 containing a recommendation that SPP be directed to continue to
pursue an RTO coalition in the Midwest. In fact, throughout the southeast mediation
process, despite strong participant support early on, SPP’s model was withdrawn from
consideration and SPP participation was limited at numerous points during the process.
The southeast mediation process produced no definitive model, nor agreement on who
will accept either of the mediated models, nor even agreement on when such
organization(s) will be formed. Throughout the mediation process, SPP Staff discussed
at length combination alternatives with representatives from neighboring systems TVA
and Southern Company. Neither party is interested in more than a better understanding
of what services SPP currently provides its members.

Midwest
Other than the MISO, there are two primary groups in the Midwest with which SPP Staff
has had discussion – The Alliance RTO and the Crescent Moon. The Alliance RTO has
received conditional FERC approval as an RTO and currently consists of predominantly
investor-owned utilities serving about 92 GW of peak load. The Crescent Moon is a
coalition of mostly non-FERC jurisdictional entities that have yet to develop or file
organizational documents. These entities serve about 6 GW of peak load.

A merger between SPP, Inc. and the Alliance RTO is problematic from the start due to a
major philosophical difference is structure. SPP is structured as a non-profit, non-asset
owning provider of RTO services. The Alliance RTO is structured as a for-profit
transmission asset-owner. Throughout the Southeast mediation, most SPP members
voiced opposition to having a for-profit, asset owner performing security coordination,
tariff administration and market operations functions – the core responsibilities of an
RTO. These are the very concerns and reasons that influenced the formation of SPP’s
current structure. If these organizations were to become one, it would not be through
merger activity, but by members of either organization joining the other – an option
available to all entities today. A functional solution to the seams issues with the Alliance
RTO could be obtained through a coordination agreement and/or the Alliance RTO
operating under the SPP in a fashion similar to that proposed for the Entergy Transco. Additionally, merging with Alliance RTO is not a high priority for them as they are intent on meeting the December 15, 2001 deadline for RTO operation, and are not interested in being distracted at this time having already received conditional FERC acceptance of their RTO filing. However, SPP Staff made repeated proposals to provide services in the formation of the Alliance RTO, which were summarily rejected, and recently Staff contacted the Alliance management committee about SPP and/or SPP/MISO providing basic RTO services to the Alliance or its proposed managing partner the National Grid. No response has been received to date and none is expected.

The members of the Crescent Moon group have indicated that they will evaluate their options on their own time schedule and will keep open the possibility of joining SPP, MISO, a new combined organization, or other possibilities. The members of Translink (a MISO transmission-only company) are looking at the draft term sheet but have not provided any details of their concerns or issues.

**Business Rationale for Merger and Asset Utilization Terms**

SPP Staff has maintained for over seven years that there is no reason to maintain multiple non-profit organizations providing the same services to electricity providers. This thinking is what drove the attempted merger between SPP and MAPP over four years ago and the previous attempted merger between SPP and MISO nearly two years ago. Unfortunately, the plethora of market structure changes and varying and diverse business interests of members of the regional entities and their Boards have stymied such combinations. Though conditions are no less hostile to such a combination today, a combination remains the right thing to do.

The ultimate goal of any merger of organizations is greater efficiency and effectiveness. Completion of the due diligence review based on a combination has not only revealed favorable financial effects of the combination from SPP and MISO corporate perspectives, but also there are additionally very real but somewhat unquantifiable benefits of the combination from a market and operations effectiveness perspective. After all, neither organization was created based on cost savings, but rather on market effectiveness from reliability and commerce perspectives. The provision of one-stop shopping for transmission service at non-pancaked rates across such a vast area with standardized terms, conditions, and business practices will vastly improve market efficiency and enhance reliability with the ability to manage, schedule and provide compensation for parallel flows occurring largely in a north/south direction. This value is somewhat hard to quantify but is undoubtedly mammoth in comparison to the current and projected operating costs of both SPP and MISO. This realization impacted many of the provisions in the draft merger term sheet, specifically with respect to utilization of facilities and employees, personnel, locations and functions per location and valuation of assets.
A strong influence in development of term provisions was and remains the realization that SPP has a contractual and regulatory obligation to continue providing transmission service pursuant to its regional tariff, and the new organization will have the same responsibility over a much larger area. This requires experienced personnel with established customer and member relationships (an expensive and limited resource), and systems that are customized to specific tariffs (a very expensive and very limited resource). With respect to personnel, neither organization is staffed to its approved level so efficiencies should be achievable while maintaining most, if not all, existing employees. Also, both organizations had approved staffing levels well below all other functioning or proposed ISOs and/or RTOs and some staff growth was projected in future year budgets.

With respect to maintaining multiple office locations, both organizations have invested heavily in custom facilities, which have minimal value in the office space market. Therefore, depreciation of these assets in the form of utilization appears to be the most efficient short-term decision, especially considering the need for redundant sites for secure backup purposes. From a business perspective, with office space being relatively inexpensive, maintaining multiple office locations for some period of time seems particularly reasonable in order to maintain experienced personnel who will not relocate. Other reasons for maintaining multiple locations include: the desire to maintain a more local presence over a 20+ state area (regulatory offices may someday be appropriate in each state); the ability to attract more and better personnel given multiple location options; the lack of relevance of office locations to the functions performed and services provided; and more flexibility to respond to future decisions. The location of specific functions should and is contemplated to be a management decision of the new organization.

Assets were proposed to be valued at book cost due to the newness of systems, the lack of booked depreciation at this time, and the inability to rationally determine another method of valuation. Also, since both entities are not-for-profit and the tariffs are designed to recover all costs, by definition, the book value of the entity is the unrecovered cost reflected on the balance sheet. And, since no profit is earned, no retained earnings or equity should appear on the balance sheet and no premium can be paid in excess of book value to reflect a profit potential in excess of the cost recovery.

Financial Analysis of Merger
For the purpose of financially analyzing a merger of SPP and MISO, balance sheets as of July 31, 2001 were combined and adjusted to produce a year-end estimate (Combined Balance Sheet – Attachment 2). Each organization also developed draft 2002 budgets for stand-alone operation, which were combined to produce a total budget prior to realizing any synergies from the merger (Combined Budget Summary – Attachment 3). Both organizations reviewed customer load estimates and, assuming all load is subject to an administration fee, budgeted expenditures were applied to these load figures to obtain costs per MWh of load served. SPP’s stand-alone cost is...
estimated to be $0.127/MWh compared to $0.124/MWh for the combined organization. Based on the projected assumptions, without recognizing any synergies from the combined organization, SPP member cost is reduced. All calculated costs include an expense allocation for repayment of MISO and SPP debt. Synergies from the combination are estimated to be:

- Reduction in expected staffing of the uncombined organizations of SPP, MISO and MAPP from 311 to 280 (approximately the current staffing level of the three organizations), results in approximately $3.3 million in savings vs. budget;
- Reduction of employee related operating expenses of 10% (approximately $574,000 in savings);
- Reduction of consultant and outside services of 30% (approximately $4.2 million in savings), and
- Employee benefits are expected to be cost neutral to both organizations with no degradation in benefits to either group of employees. An initial comparison of benefit plans is complete and this goal is believed to be achievable.

These estimated synergies amount to approximately $8 million in the combined organization and produces a combined cost of $0.119/MWh. Merger expenses could significantly offset this savings in the first year.

If the Crescent Moon group were to participate in the combined organization, customer cost is estimated at $0.111/MWh. If Entergy were to participate in the combined organization, customer cost is estimated at $0.096/MWh. If both the Crescent Moon group and Entergy participate, customer cost is estimated at $0.091/MWh. As stated in the business rationale section above, any of these costs pale in comparison to the benefits of the combination from a market and operations effectiveness perspective. Taking all of these estimated costs into comparative perspective, customer costs for PJM, ERCOT, Ontario and CalISO are $0.35, $0.22, $0.90 and $1.00 respectively.

**Legal Analysis of Merger**

SPP has employed Wright, Lindsey & Jennings as legal counsel for the legal review portion of the due diligence process. This firm provided counsel to SPP for the recent financing project and has assisted a number of businesses through mergers. The team assembled to assist with the merger has considerable experience in mergers, and sufficient experience in public utility mergers to understand the nuances they may present.

SPP and MISO have been exchanging considerable documentation in recent weeks as part of the due diligence process. There are some documents that each consider either too cumbersome or too sensitive to copy outside their companies and these will be reviewed during on-site visits. Travel has been impeded, but trips are being re-scheduled as soon as practicable. In the interim, there are a considerable number of documents that have been exchanged via email and hard copy; these are being evaluated as received.
Points of interest to date:

- An evaluation of whether Hart-Scott-Rodino filings will be required is underway. Initial evaluations indicate the filings may be avoided, but confirmation is pending. The goal is to avoid these filings as a matter of time, as well as to avoid the $45,000 filing fee.
- Of particular interest are MISO’s agreements with other organizations, namely, The Alliance, MAPP, MAIN, Manitoba Hydro, and Detroit Edison and the impact any of them may have on a merger. The Alliance filings are available and under review; SPP has not received nor had an opportunity to review the agreements with MAPP, MAIN, and Manitoba Hydro.
- MISO’s financing documents will have to be reviewed during an on-site visit. SPP has been advised that there are 12 debt holders, and that their consent is not required in the event of a merger.
- While MISO owns the land at its location, it occupies its building under a lease-purchase agreement. The terms related to that agreement are not yet known.

As stated, as much information as possible continues to be exchanged in advance of on-site trips. A full report of the results of the legal review will be provided upon its completion.

**Equity in Governance**

The Board of Directors requested formation of a negotiating committee on governance, which has been created and consists of Tom McDaniel, Harry Skilton, and John Oxendine from SPP and Bill Vititoe, Bill Albertini, and Jim Young from MISO. This group has yet to meet, but will provide a report and appropriate recommendations to the respective boards of directors at a later date.
Draft Term Sheet

Whereas, the Midwest Independent Transmission System Operator, Inc. ("MISO") and the Southwest Power Pool, Inc. ("SPP") (individually each a party and collectively the parties) each are engaged in the business of providing open access transmission service over facilities committed to their control by transmission owning members; and

Whereas, the parties are desirous of exploring the basis upon which a possible combination or other business transaction involving the parties might take place,

Based on the mutual premises presented below, the parties agree as follows:

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<th>Dave Christiano</th>
<th>Where does Crescent Moon fit in?</th>
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<tr>
<th>Dick Dixon</th>
<th>In addition, we need to have a good understanding as to how this transaction will interact with the MISO/ARTO agreements, Crescent Moon and Translink and further, how it will satisfy FERC’s vision for a Midwest RTO.</th>
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<td>WRI</td>
<td>RESPONSE</td>
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<td>The members of Crescent Moon group have indicated that they will evaluate their options on their own time schedule and will keep open the option of joining SPP, MISO, NEWCO, or other possibilities. The issue of MISO/ARTO will be covered later in other responses. The members of Translink are looking at the agreement but have not provided any details of their concerns or issues. The Term Sheet deals with FERC in a later response.</td>
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<tr>
<th>Dick Dixon</th>
<th>In addition to the above points, there are several items omitted from the draft terms that are critical to an agreement on the transaction. They include form of membership agreement, bylaws, exit provisions, stranded costs, cost recovery, etc.</th>
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<td>WRI</td>
<td>Harry Skilton Comments on the term sheet relate primarily to the need for more information to assess our position.</td>
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<tr>
<th>Harry Skilton</th>
<th>We need to have a better understanding of our relative strength and weaknesses SPP/MISO/Alliance; it is also not clear to me if MISO has been “anointed” by FERC and therefore has an upper hand at the same time, I don’t know how “electrons” flow but it seems to me that SPP has a strategic location on the map with a “natural” linkage northward as well as toward s the south east which would be desirable for expansion of the new merged SPP/MISO/RTO. In any event, an analysis of these issues would be helpful in assessing our posture.</th>
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<td>Harry Skilton Secondly, are there significant differences in operating philosophies</td>
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<th>Comment</th>
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</thead>
<tbody>
<tr>
<td>Harry Skilton</td>
<td>My main concern regards the done and approach of MISO. The corporate governance procedures they propose are “under their terms”; their by laws and procedures prevail.</td>
</tr>
<tr>
<td>Shantha Varahan OCC</td>
<td>How do SPP’s and MISO’s by laws and operating procedures compare; How do they differ? It needs to be clearer the role of the parties in this mediation process. What does each side bring and offer for the total RTO formation process? What roles can each have and maintain. It seems as though each is in a survival mode. No one seems to want to give up any control. The corporate governance procedures proposed by MISO are “under their terms”; and if adopted, MISO’s by laws and procedures would prevail.</td>
</tr>
<tr>
<td>Robin Kittel XCEL</td>
<td>In general, SPS supports the SPP and MISO merger; however, SPS feels strongly that certain logistical aspects leading up to the agreement of Terms need better definition. SPS believes that it is essential that the Board, (or some subset thereof), in order to satisfy its fiduciary responsibility to its members, must be instrumental in the negotiations of the SPP/MISO Term Sheet. SPS believes that for this effort to be successful the negotiation of critical details must reflect a broad array of SPP member interests. Thus, we recommend the Board establish a specific negotiating committee that is reflective of the SPP membership that is predominately responsible for paying the current SPP fees and potentially the future NEWCO fees.</td>
</tr>
<tr>
<td>Robin Kittel XCEL</td>
<td>Associated with the Board’s involvement in the negotiation of the SPP/MISO merger, the Board should direct SPP staff to focus on merger negotiations and suspend activity related to any legal pursuits beyond their current FERC Request for Rehearing of Southwest Power Pool, Inc.¹ We believe that such efforts may prove counter productive with future FERC negotiations. Instead, the Board and Staff should spend their time and effort complying an accurate, and thorough evaluation of the financial standing of SPP and on finalizing the proposed merger. SPS believes that there could be economic benefits and synergies associated with the merger of SPP and MISO and support the efforts of the Board in making this determination.</td>
</tr>
<tr>
<td>Kim Casey Dynegy</td>
<td>We also agree with OG&amp;E’s comments that the merger negotiations should not be limited to the 2 presidents of the existing organizations.</td>
</tr>
<tr>
<td>Dave Christiano CUS</td>
<td>In the current SPP by-laws, &quot;Transmission Owning Member&quot; is not equal to &quot;Transmission Owner.&quot; This distinction may not be important with a fully independent board. In SPP, for example my</td>
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<tr>
<th>Name</th>
<th>Company/Delegation</th>
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<tbody>
<tr>
<td>Dick Dixon</td>
<td>WRI</td>
<td>company is a &quot;Transmission Owner&quot; but not a &quot;Transmission Owning Member,&quot; therefore I sit on the &quot;Transmission Using Member&quot; sector of the board. Under NEWCO, would any member with transmission facilities under either tariff be classified as a &quot;Transmission Owning Member?&quot;</td>
</tr>
<tr>
<td>Harry Dawson</td>
<td>OMPA</td>
<td>There is a statement at the end of this paragraph providing that Non-transmission owner members of the MISO and SPP would become non-transmission-owning members of Newco without additional cost to them. It is not clear why this indemnification is appropriate. The statement should be explained or eliminated, or a similar indemnification should be extended to transmission owners.</td>
</tr>
<tr>
<td>Michael Gildea</td>
<td>DENA</td>
<td>What is the purpose for SPP remaining as regional reliability council? Seems like this is a potential argument with MISO over asset/liability splitting.</td>
</tr>
<tr>
<td>Bill Dowling</td>
<td>MWE</td>
<td>DENA suggests removal of the sentence &quot;SPP as a regional Reliability Council would continue in existence unchanged by the transaction.&quot; This term sheet deals with the proposed union of what are now two proposed RTOs. NERC reliability councils are totally separate entities from RTOs and hence this reference is misplaced. Examined in reverse, as proposed boundaries for RTOs have been shifting around over the past year, were the boundaries shifting in these NERC councils? Second, even if the statement was appropriate, one needs to question the necessity of maintaining SPP as a separate regional council given that Entergy is joining one RTO in the SERC reliability region and the remainder of this proposed RTO is joining an RTO in the MAIN reliability. Why maintain in essence what could be viewed then as a small &quot;seams&quot; regional council between two RTOs?</td>
</tr>
<tr>
<td>Dave Christiano</td>
<td>CUS</td>
<td>While I suspect there is strong sentiment toward retaining the identity of SPP as a NERC Regional Reliability Council, the structure of such an entity could lead to duplication of resources. Would members of the Newco staff be assigned to the various planning and reporting functions required of a regional reliability council, or would SPP continue to have its own separate staff for this purpose?</td>
</tr>
<tr>
<td></td>
<td></td>
<td>I'm sure we all want this marriage to be a fair and lasting one. In the last effort, fiscal matters were a prime reason for our reluctance. Our duty remains to that of members, who have financed this organization mostly &quot;out-of-pocket&quot; for decades. This is in stark contrast to MISO who have funded a &quot;start-up&quot; as most are, through a significant financing. I want to be convinced that while we join as equals, each organization's equity (we have more) and debt (they have more) are properly reflected.</td>
</tr>
<tr>
<td>Name</td>
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</tr>
<tr>
<td>Richard Verret</td>
<td>The Term Sheet provides that assets and liabilities of MISO and SPP would be contributed, transferred to or assumed by NEWCO at book value. This is unacceptable. Any merger with another organization must be preceded by a fair appraisal of the value to the new organization of the assets and liabilities brought to the new organization by the combining entities. Any agreement between SPP and MISO should make clear that SPP members would not be liable for MISO liabilities incurred prior to the combination except to the extent that an appraisal shows that the associated assets have value to SPP members. An appraisal of the assets of SPP and MISO should be provided for in the Agreement and contributions should be based on the appraisal, not book value. Investments by MISO (and SPP for that matter) that have no use to SPP members should be written off before the combination is consummated so that SPP members are not obligated for MISO assets or liabilities that are not useful or otherwise valuable to SPP members that join the combined organization.</td>
<td></td>
</tr>
<tr>
<td>Frank LeDoux</td>
<td>It would be wrong for SPP to incur costs associated with a possible merger with MISO, on behalf of those SPP members who will be advantaged by that merger, if those costs are intended to be imposed upon SPP members who may be forced by the layout of the system and economics to become part of a new RTO-SE (or similar RTO) instead. If SPP incurs any additional obligations, between now and October 1, 2002, in order to benefit only those members who choose to go forward with MISO, then LUS would take the position that it is not fair, just or reasonable for SPP to impose those costs on those members whom it knows are not going to be able to go forward with MISO.</td>
<td></td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>This document fails to identify the functions of each party mentioned with any degree of specificity. Instead it offers that Newco is to perform the FERC Order 2000 functions. SPP is to act as the regional Reliability Council. Newco is to be the Security Coordinator. Each function should clearly be stated and the party responsible to perform that function should be identified.</td>
<td></td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>What is the purpose for SPP remaining as regional reliability council? [How will MISO, Newco and SPP relate to SPP as a regional Reliability Council while Newco acts as security coordinator? How will this work? Will MISO and Newco defer to SPP on regional reliability issues?]</td>
<td></td>
</tr>
<tr>
<td>J. M. Shafer</td>
<td>Shouldn’t there be some accounting or inventory of “book value assets”. Each owner should have some idea of what the liability of MISO and SPP are to insure they don’t take on an additional burden</td>
<td></td>
</tr>
<tr>
<td>Name</td>
<td>Organization</td>
<td>Comment</td>
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</tr>
<tr>
<td>J. M. Shafer</td>
<td>WFEC</td>
<td>The remaining separate reliability councils is a little confusing?</td>
</tr>
<tr>
<td>Brenda Blundell</td>
<td>OGE</td>
<td>The assets and liabilities of SPP and MISO should include all of the assets and related liabilities of the respective organizations that will be transferred to NEWCO, including tariff under collections. Implicit in this statement is the retention of such assets as are necessary for the SPP to continue to provide its Regional Reliability Council services. Some of the assets to be transferred may have little or no value to NEWCO. As a result, the assets to be transferred to NEWCO should be appraised, and the value of the asset as transferred should be reflected at the lower of book value or the appraised value. Any difference between book value and a lesser appraised value should be considered as part of the start-up costs of NEWCO to be paid by the respective members of SPP and MISO prior to start-up of NEWCO. The Term Sheet should not codify the perpetuity of existing reliability councils.</td>
</tr>
<tr>
<td>Kim Casey</td>
<td>Dynegy</td>
<td>Following AEP’s comments, it is imperative that we obtain descriptions of the major assets and liabilities of the two organizations, as well as their respective values in order to go forward. Otherwise we are shirking our fiduciary obligation to the organization.</td>
</tr>
<tr>
<td>Harry Dawson</td>
<td>OMPA</td>
<td>In form of Newco any basis &quot;for profit sub's&quot; needs to be clearly spelled out. OMPA, GRDA, and I suspect SWPA all have to be very careful of how something like this gets set up. We are not the only ones.</td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>OCC</td>
<td>Is it agreeable that a not-for profit corporation have For-Profit subsidiaries? Does it defeat the purpose for which it was formed?</td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>OCC</td>
<td>The reasons for and the role of the for-profit subsidiaries need to be clarified.</td>
</tr>
<tr>
<td>Brenda Blundell</td>
<td>OGE</td>
<td>While this provision contemplates NEWCO to be a not-for-profit corporation when it is formed, paragraph 12 permits the Board of NEWCO to convert the corporation to a for-profit entity. OG&amp;E believes that the membership of NEWCO rather than the Board should have the right to decide whether NEWCO should be converted to a for-profit corporation, and that membership vote should require a 2/3 majority of all members for the proposition to pass.</td>
</tr>
</tbody>
</table>
| Harry Dawson        | OMPA         | In # 3, business, a number of issues.  
  a) Would like clearer definition of how Transco's will be handled.  
  b) What does the sentence "Newco will act as security coordinator for the area of its contract customers." mean? I assume this is for the area of its contract customers.  |
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<tbody>
<tr>
<td>Mike Deihl</td>
<td>Is the language too restrictive? Southwestern reads this as the NEWCO can only provide services that are covered in the FERC Order 2000.</td>
</tr>
<tr>
<td>SWPA</td>
<td>In regards to NEWCO being the Security Coordinator for the entire footprint, who’s facilities (system, equipment, resources) would be used? Southwestern believes SPP has many of the systems and resources in place to perform this for the entire footprint of the proposed NEWCO. Does MISO? How would costs be handled (apportioned)?</td>
</tr>
<tr>
<td>Bill Dowling</td>
<td>The first sentence of this paragraph appears to be a little too narrow, in that it addresses only Order 2000 services. Depending on the answer to question #3 above, this should perhaps be defined somewhat more broadly. Perhaps language such as the following would work: Newco would be in the business of providing regional transmission administration and planning services and RTO/FERC Order 2000 services on a bundled basis and on an unbundled or menu basis, and would be the RTO covering the MISO and SPP regions.</td>
</tr>
<tr>
<td>MWE</td>
<td>The fourth sentence suggests that Newco could offer services on a contract basis. Is this intended to be services to other regions outside Newco? If so, then move this sentence at least to the end of the paragraph, and make it clearer.</td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>The Newco is to provide RTO/FERC Order 2000 services. These services should be spelled out.</td>
</tr>
<tr>
<td>OCC</td>
<td>Is the Newco limited to providing only the services that are covered in the FERC Order 2000?</td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>In regards to Newco being the Security Coordinator for the entire footprint, who’s facilities (system, equipment, resources) would be used? Does SPP have the systems in place to perform as Security Coordinator for the entire footprint? Please note that Southwestern believes SPP has many of the systems and resources in place to perform this for the entire footprint of the proposed NEWCO. Does MISO? How would costs be handled (apportioned)?</td>
</tr>
<tr>
<td>OCC</td>
<td>Finally, Xcel Energy has been working with the MISO under Appendix I to allow for the formation of TRANSLink, LLC. We understand that there is no intent for the SPP/MISO merger to change that direction, and would request positive confirmation to that effect. These conclude SPS’ comments on the conditions of the draft SPP/MISO Term Sheet.</td>
</tr>
<tr>
<td>Robin Kittel</td>
<td>OG&amp;E believes there should be a clearer recognition of</td>
</tr>
<tr>
<td>XCEL</td>
<td></td>
</tr>
<tr>
<td>Brenda Blundell</td>
<td></td>
</tr>
<tr>
<td>Name</td>
<td>Comment</td>
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</tr>
<tr>
<td>OGE</td>
<td>TRANSCO’s, GRIDCO’s, and ITC’s within the NEWCO RTO footprint. Careful attention should be given to the relationship developed in the SPP to accommodate TRANSCO organizations, and that approach should be captured in the NEWCO enabling documentation.</td>
</tr>
<tr>
<td>Kim Casey Dynegy</td>
<td>First Sentence – what are Order 2000 services? – Order No. 2000 required transmission providers to form or join regional transmission organizations. Presumably Newco will provide open access transmission and related services.</td>
</tr>
<tr>
<td>Kim Casey Dynegy</td>
<td>Sixth Sentence – Change “for” to “within” before “the footprint”. Does this mean if the contract customers agree?</td>
</tr>
<tr>
<td>Dick Dixon WRI</td>
<td>The board should immediately appoint a committee (RTOWG or perhaps more appropriately, a group of transmission owners) to begin a detailed negotiation with the MISO for the terms of merger. This function cannot be performed by SPP Staff or the SPP board. This process will &quot;flesh out&quot; the details that all the other commenters are rightly concerned about such as valuation of assets, revenue recovery, grandfathered agreements, Schedule 1 charges, fiduciary responsibility, cost shifting, load under the tariff, seams issues, membership agreements, voting rights, representation, non-jurisdictional participation, etc. We are wasting our time until these details are clarified.</td>
</tr>
<tr>
<td>Dick Dixon WRI</td>
<td>If so, how will transmission owners be repaid for the excess membership fees paid to date?</td>
</tr>
<tr>
<td>Harry Dawson OMPA</td>
<td>What about previous under collections?</td>
</tr>
<tr>
<td>Mike Deihl SWPA</td>
<td>The issue of NEWCO’s “adder” raises a question. Under the current SPP adder, SPP is not collecting sufficient revenues to cover all expenses. If this adder is eliminated and the new NEWCO adder is applied (with cap), what happens to the approximately $10 million dollars of unpaid expenses liability with SPP?</td>
</tr>
<tr>
<td>Richard Verret AEP</td>
<td>The Term Sheet contemplates continued use of the deferral mechanism now used by MISO to account for and finance expenses that cannot be covered by current income. This approach promotes fiscal irresponsibility. As is currently the case for the SPP, Newco should be operated on a &quot;pay as you go&quot; basis. Under this approach, a capped administrative charge would be the primary revenue source, but current assessments to members would be used to fund any revenue shortfall on a current basis.</td>
</tr>
<tr>
<td>Shantha Varahan OCC</td>
<td>The issue of NEWCO’s &quot;adder&quot; raises a question. Under the current SPP adder, SPP is underrecovering expenses. The grandfathered load</td>
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<tr>
<td>Richard Spring</td>
<td>Since SPP members have been paying for SPP's assets through annual assessments and administration fees, SPP members could end up paying for an inequitable share of the Newco's assets by also having to pay for the MISO assets through the Newco administration fees? There should there be some &quot;credit&quot; assigned to SPP members who become MISO members. Or can provisions be made to &quot;pay&quot; the MISO and SPP members for the systems they bring to the table creating Newco?</td>
</tr>
<tr>
<td>Kim Casey</td>
<td>Western Resources has a question on Paragraph 4 (No. 3) as to how transmission owners will be repaid for excess membership fees paid to date. What does this mean? It seems as though any such repayment for any existing deficiencies would be governed by existing SPP bylaws and or the tariff and FERC orders, but could not be reetermined/reallocated by this term sheet.</td>
</tr>
<tr>
<td>Mike Deihl</td>
<td>There is reference to the MISO-ARTO settlement agreement. Southwestern is not familiar with the specific terms of this agreement. Southwestern believes this should be expanded/clarified so current SPP members know what charge they are agreeing to.</td>
</tr>
<tr>
<td>Dick Dixon</td>
<td>Where are the synergies/cost savings from this merger? Is it cost justified to maintain three locations when two are sufficient? This paragraph should be eliminated, especially since it seems to be in conflict with the provisions of paragraph 6.</td>
</tr>
<tr>
<td>Harry Dawson</td>
<td>In # 5, why would there be 3 locations? Seems very expensive, and duplicative to me. Suggest near a major airport, one locations.</td>
</tr>
<tr>
<td>Mike Deihl</td>
<td>Is it either cost efficient or operationally efficient to maintain three locations?</td>
</tr>
<tr>
<td>Michael Gildea</td>
<td>While there may be a need for satellite operations centers for locations in Indianapolis, Little Rock and St. Paul for this proposed RTO, only one of these locations should be in charge and overall responsible for operations across this RTO.</td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>Why have more than one location? Is it cost efficient or operationally sound to maintain three locations? Are the locations selected easily accessible? Is there duplication of functions?</td>
</tr>
<tr>
<td>Frederick Ochsenhirt</td>
<td>In that regard, it is unlikely that Newco will need three locations.</td>
</tr>
<tr>
<td>Robin Kittel</td>
<td>With respect to the provisions of the Term Sheet, SPS believes there</td>
</tr>
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<tr>
<td>XCEL</td>
<td>should be some greater flexibility on the provision that maintains multiple locations in Little Rock, Indianapolis, and Minneapolis. We recognize the need for multiple locations from a transitional perspective, but believe there may come a point where a more consolidated operation would benefit the SPP members and other transmission customers by gaining certain cost and operational efficiencies.</td>
</tr>
<tr>
<td>Brenda Blundell OGE</td>
<td>It makes little sense to perpetuate three separate locations for NEWCO. While three locations may be necessary during some short transition period, NEWCO headquarters should be located so that access by all members and members of the Board is cost effective. OG&amp;E proposes that the Board and all meetings of the Stakeholder Advisory Committee (SAC) be held in St. Louis, Missouri from the outset. OG&amp;E nominates St. Louis because it is centrally located within the geographic area to be covered by the NEWCO RTO footprint, and St. Louis serves as a major airline hub, thus facilitating travel to Board and SAC meetings.</td>
</tr>
<tr>
<td>Kim Casey Dynegy</td>
<td>We agree with Western Resources and OMPA that there is no cost justification for maintaining 3 locations and that this provision should be eliminated or it should state that within a reasonable time period, Newco will establish a single location.</td>
</tr>
<tr>
<td>Richard Spring KCPL</td>
<td>Functions to be performed at the three locations need to be identified ASAP.</td>
</tr>
<tr>
<td>Brenda Blundell OGE</td>
<td>The Term Sheet should specify that operations continue at the existing locations during a transition period not to exceed one year.</td>
</tr>
<tr>
<td>Kim Casey Dynegy</td>
<td>SPP and other proposed RTO organizations have been ordered by FERC to not incur start up costs prior to FERC’s approval as RTOs and prior to implementation of fully independent boards of directors that will make business decisions for the new organizations.</td>
</tr>
<tr>
<td>Dave Christiano CUS</td>
<td>How was the 8/5 split determined? If on a size ratio did SPP include Entergy?</td>
</tr>
<tr>
<td>Dick Dixon WRI</td>
<td>The board composition is tilted too far in MISO’s favor. Unless the voting rules require a 3/4s majority, MISO will be able to control all outcomes. I believe a better approach would have been a split of 7 to 6 with a 2/3s majority on voting. Another option may be for the SPP to pick the MISO board members and to let MISO pick SPP’s board members.</td>
</tr>
<tr>
<td>Harry Dawson OMPA</td>
<td>In # 7, as a bare minimum, I think it should take a 2/3 majority to do significant items.</td>
</tr>
<tr>
<td>Mike Deihl SWPA</td>
<td>This was discussed fairly intensely at the SPP BOD meeting. Southwestern still believes some fairness and equality should be established. Southwestern would support the seeking of FERC.</td>
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ordering mediation on this issue if MISO doesn’t want to move.

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<th>Name</th>
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<tr>
<td>Harry Skilton</td>
<td>The new company Board should have a Board committee that would meet in executive session to review, propose, and report on the following subjects.</td>
</tr>
<tr>
<td></td>
<td>• Corporate governance (board and top officer performance; board structure and procedures)</td>
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<tr>
<td></td>
<td>• Finance and Audit (audits, budgets, financing, insurance, pension funds)</td>
</tr>
<tr>
<td></td>
<td>• Compensation and Benefits (human resource systems)</td>
</tr>
<tr>
<td>Richard Verret</td>
<td>The Term Sheet contemplates an imbalance in the ability of MISO and SPP to appoint independent members to the MISO Board. This imbalance (eight members from MISO and five for SPP) is apparently based on relative generating capacity connected to MISO and SPP transmission facilities. Because the Newco Board is to be independent, its members should be nominated by the two combining organizations in equal proportions. The independent board should then select the new CEO and other members of the management team.</td>
</tr>
<tr>
<td>Shantha Varahan OCC</td>
<td>What style of leadership will the Newco Board have? Will it be collaborative style as used by the SPP?</td>
</tr>
<tr>
<td>Shantha Varahan OCC</td>
<td>What process will be followed to reduce the number of board member seats from 12 to “less than 10 members over the ensuing five years”? Is it appropriate that the Newco Board be comprised of SPP Board and MISO Board members. Is this independent enough?</td>
</tr>
<tr>
<td>Frederick Ochsenhirt ETxC</td>
<td>Second, the East Texas Cooperatives have voiced their support for an independent Board. However, the SPP should insist on equal representation on the Newco Board. If the MISO is truly interested in this consolidation, and from all indications they are, they will be flexible on governance issues.</td>
</tr>
<tr>
<td>Richard Spring KCPL</td>
<td>The Newco Board should be elected from a slate of candidates (can be the existing members from the two boards) by the members. Otherwise seat both Boards and immediately start a process to reduce the number to seven. A super majority should be required of any board actions since they are independent and may know little about the industry.</td>
</tr>
<tr>
<td>Brenda Blundell OGE</td>
<td>The independent Board of NEWCO should be selected initially with equal representation from MISO and SPP. This Board should serve for an interim period with a transition in two years for staggered term elections of Board members nominated at large by all members of the NEWCO RTO. Affirmative Board action should require a 2/3 approval of the Board members present and participating in any vote.</td>
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</tr>
<tr>
<td>Kim Casey Dynegy</td>
<td><strong>First sentence – Change to read “An independent Board will govern Newco and will consist of eight independent members of the MISO board, and five independent board members from SPP.”</strong></td>
</tr>
<tr>
<td>Kim Casey Dynegy</td>
<td><strong>If we fulfill our fiduciary responsibility to this organization and determine the approximate value of MISO prior to entering into this Draft Term Sheet, it may be that MISO’s debt will limit its ability to force its preferred governance structure on the existing SPP members. The stakeholders of the organizations should elect each and every member of the Newco board. The stakeholders may choose to elect one or both of the existing Presidents. However, their presence on the board should not be predetermined simply by virtue of the fact that they are to date the sole negotiators of this agreement. The existing Presidents are not necessarily “independent”. Maintaining the existing Presidents as members is not consistent with the objective of forming a merged organization, nor does it provide any incentive to these officers to prove their value to the new organization.</strong></td>
</tr>
<tr>
<td>Mike Deihl SWPA</td>
<td><strong>Is the term lengths of the board membership an initial set of staggered years, or would this be a permanent and continuing rotation?</strong></td>
</tr>
<tr>
<td>Bill Dowling MWE</td>
<td><strong>As the initial Board members are assigned to term groups, care should be taken to ensure that each term group has equal representation from the MISO and SPP predecessors.</strong></td>
</tr>
<tr>
<td>Shantha Varahan OCC</td>
<td><strong>Is the term lengths of the board membership an initial set of staggered years, or would this be a permanent and continuing rotation?</strong></td>
</tr>
<tr>
<td>Dave Christiano CUS</td>
<td><strong>SPP has two Stakeholder Advisory Committees (EOC and CPC). Can stakeholders get adequate representation from a single group? If we are going to have an independent board, I would like to increase the stakeholder input well beyond the current MISO model.</strong></td>
</tr>
<tr>
<td>Dick Dixon WRI</td>
<td><strong>In the absence of a stakeholder board, we must carefully consider the role of the Advisory Committee to insure adequate representation. It is unreasonable to limit the Committee to only three representatives (one each from MISO, SPP and MAPP) from each sector. Remember, in the SPP, each member has a seat on the advisory committees (EOC and CPC) and theses committees report to a stakeholder board. Under Newco, the stakeholder board is eliminated and advisory committee representation would be reduced by a factor of 10 or more. I believe the board should be seeking more, rather than less, input from the stakeholders.</strong></td>
</tr>
<tr>
<td>Harry Dawson OMPA</td>
<td><strong>In # 7, second Para, please flesh out the exact role of the stakeholders committee's, how appointments are made, and how they input to the</strong></td>
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<td>Name</td>
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<td>Mike Deihl</td>
<td>SWPA</td>
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<td>Harry Skilton</td>
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<td>Bill Dowling</td>
<td>MWE</td>
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<td>Michael Gildea</td>
<td>DENA</td>
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<td>Shantha Varahan</td>
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<td>Richard Spring</td>
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<td>Kim Casey</td>
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<tr>
<td>Brenda Blundell</td>
<td>OGE</td>
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(TDU’s), and Transmission Users (IPP’s and marketers). Selection of Members to the SAC from SPP, MAPP, and MAIN should be a transition approach not to exceed 5 years, after which SAC Members should be elected by the respective categories on an at-large basis. Membership on the SAC should also be rotated on a staggered term basis.

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<tr>
<td>Kim Casey</td>
<td>Add at first of paragraph. “Sector voting for the Stakeholder Advisory Committee will be structured as follows: Newco Members are permitted to participate in multiple categories. In order to avoid undue influence by a single Member, Newco Members and affiliates are limited to a single category for voting purposes and are required to elect their sector category for a preestablished period, e.g., one year.”.</td>
</tr>
<tr>
<td>Kim Casey</td>
<td>In the ARTO Advisory Committee meeting on August 21, 2001, many of the stakeholders indicated a preference for weighted sector voting for the Advisory Committee, ala PJM. For example, all generator entities in that category are permitted to vote and the votes are weighted accordingly (If there are 10 total votes and generators have 2 votes, if 10 generators are present and vote, each generator’s vote would count 1/5). Weighted sector voting permits and encourages broader participation. This draft term sheet should not adopt terms that will preclude the utilization of weighted sector voting. Any member category should be permitted to adopt weighted sector voting if that is their preference. This suggestion may respond to Western Resources’ and Cities of Springfield’s concerns regarding inadequate representation.</td>
</tr>
<tr>
<td>Dave Christiano</td>
<td>Regarding executive sessions, strike under (d) &quot;transactions or&quot; and (g) in its entirety.=</td>
</tr>
<tr>
<td>Dick Dixon</td>
<td>There are too many exceptions to the open meeting rule. In particular, discussions on (d) business transactions or combinations, (e) consideration of the sale or purchase of securities, investments, or investment contracts and (g) discussion of emergency and security procedures should not be closed to members. Also, unless there are collective bargaining employees involved, item (f) should be deleted.</td>
</tr>
<tr>
<td>Harry Dawson</td>
<td>In # 7, there are way to many things that the board can consider in executive session. This is a non stakeholder board. There appears to be way to much potential for something to be considered in executive session that would exclude interested parties for hearing (and inputting) the debate.</td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>What matters will be subject to open meeting? What type of functions will be dealt with in Executive Session? It appears that the important items and the majority of the items are dealt with in</td>
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<tr>
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<td>Harry Dawson</td>
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<td>Kim Casey</td>
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<tr>
<td>Richard Verret</td>
<td>AEP</td>
</tr>
<tr>
<td>Name</td>
<td>Comment</td>
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<tr>
<td>Frederick Ochsenhirt</td>
<td>In addition, MISO has expended a substantial amount of money in start-up costs. SPP members should not be liable for any of these costs. Likewise, existing MISO members should not be liable for any SPP start-up costs.</td>
</tr>
<tr>
<td>Brenda Blundell</td>
<td>As stated above, valuation of assets and liabilities should be subject to appraisal, and transfer of assets and liabilities should be <strong>at the lesser of book value or appraisal value.</strong></td>
</tr>
<tr>
<td>Richard Verret AEP</td>
<td>The Term Sheet provides that current officers’ contracts will remain in effect and the Newco Board will determine actual appointment of individuals to specific officer positions. Care should be taken in writing new contracts for SPP personnel that the new contracts do not give such employees a biased incentive to pursue a combination with MISO as opposed to some other alternative or get in the way of optimizing any new organization that SPP members may join.</td>
</tr>
<tr>
<td>Dick Dixon WRI</td>
<td>Once again, where are the cost savings, or at least an agreement to minimize costs consistent with Newco’s mission? Is it really appropriate to include a statement in this Term Sheet regarding Newco’s intent to retain all existing employees and facilities? It would help to state that existing employees and facilities will be used initially but that Newco is free to combine or eliminate functions in the future following an orderly transition to merged operations.</td>
</tr>
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</table>
| Bill Dowling MWE      | Is the intent of the first sentence to retain all employees of MISO and SPP, and thereby forego any savings that might be available by eliminating overlap? Guaranteed employment for current employees should not be a primary goal of Newco. Similarly for facilities; why should it be a goal to use a facility that is no longer needed after the formation of Newco? Since efficiency should be a primary target of Newco, perhaps the following language is more appropriate:  
“**It is the intent of the MISO and of SPP that all facilities and employees remaining after the formation of Newco be fully utilized. Efforts will be made to reduce the number of needed employees and systems to recognize the efficiencies of this combination.”** |
<p>| Richard Verret AEP    | The Term Sheet fails to recognize that the Newco must be operational by December 15, 2001 to comply with Order No. 2000 and also fails to indicate when the combined organization would be ready to operate or who would have responsibility for operation pending |</p>
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<tr>
<th>Name</th>
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<tr>
<td>Brenda Blundell</td>
<td>OGE</td>
<td>This provision of the Term Sheet should refer only to employees. Thus the heading should read, “UTILIZATION OF EMPLOYEES”. The first sentence of this provision should be stricken. With the consolidation of functions at one location, it makes little sense to perpetuate the costs of maintaining separate offices any longer than necessary to move from the transition period to the end state.</td>
</tr>
<tr>
<td>Kim Casey</td>
<td>Dynegy</td>
<td>We agree with Western Resources – preservation of all existing facilities and employees has not been demonstrated to be consistent with Newco’s mission and purpose. As drafted, the term sheet essentially preserves the existing organizations – essentially agreeing to “hold hands” -- as opposed to a true merger.</td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>OCC</td>
<td>This appears to be a safety net for those holding current positions at SPP and MISO. Is this appropriate? Is there duplication of function? If the costs are being recovered, is this cost effective? (If fees are incorporated for recovery from ratepayers, is there harm?)</td>
</tr>
<tr>
<td>Brenda Blundell</td>
<td>OGE</td>
<td>MISO and SPP should be separately responsible for the liability of officer contract termination with those costs being directly assigned to the members of the existing organizations as a part of the winding down of the respective MISO and SPP Boards obligations.</td>
</tr>
<tr>
<td>Mike Deihl</td>
<td>SWPA</td>
<td>What type of incentives are being referred to (individual financial rewards)? Is this section necessary at this time? This is something that could be developed later by the NEWCO, if needed.</td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>OCC</td>
<td>What type of incentives are being referred to regarding individual performance/rewards?</td>
</tr>
<tr>
<td>J. M. Shafer</td>
<td>WFEC</td>
<td>What are the incentives for performance. We could very well get into an issue of losing employees or sending the wrong signals to those employed by the RTO.</td>
</tr>
<tr>
<td>Brenda Blundell</td>
<td>OGE</td>
<td>OG&amp;E believes that incentives should not be limited to the present world paradigm. This term should read, “The MISO and SPP agree that incentives must be developed for employees and officers of NEWCO.”</td>
</tr>
<tr>
<td>Kim Casey</td>
<td>Dynegy</td>
<td>We agree Newco needs incentives. More specificity as to what type incentives this provision refers to, e.g., financial.</td>
</tr>
<tr>
<td>Brenda Blundell</td>
<td>OGE</td>
<td>The date in the first bullet-point in this paragraph should be changed to October 1, 2001.</td>
</tr>
<tr>
<td>Kim Casey</td>
<td>Dynegy</td>
<td>Why was September 1 chosen? Is this date realistic?</td>
</tr>
</tbody>
</table>
Dynegy

Rick Henley
CWL-J

I would think we would want both the MISO & SPP books audited prior to transferring to Newco.

Rick Henley
CWL-J

Would we really want a not-for-profit corporation spinning off for-profit subsidiaries?

Rick Henley
CWL-J

Why does FERC have to approve a customer as an ITC or Transco to receive service? What type of services would Newco offer on a commercial contract basis?

Rick Henley
CWL-J

Is it really necessary to have three separate locations? It would seem - this would cost more.

Rick Henley
CWL-J

The board and Governance Structure should be fair and split evenly.

Rick Henley
CWL-J

I do not think that one representative for each region in sufficient to represent a balanced opinion from that sector.

Rick Henley
CWL-J

If you are going to specify that a Transmission Owners Committee be formed - then you should also specify the other committees.

Rick Henley
CWL-J

The incentive required would be a job well done for a job paid well. Why should you pay someone for dong what is right.

RESPONSE

In the next month, SPP and MISO will be exchanging information, documents, contracts, by-laws, etc. that will go through a legal, business, and economic review, and will provide more information regarding the combination. This results in the definitive documents referenced in the last part of this term sheet to create Newco bylaws, membership agreements, operating policies, articles of incorporation, etc. The assumptions of Newco functions, staffing (including incentives), and systems (including for-profit subs) will need to be highlighted and explained, including providing services outside the Newco footprint (contract customers are functions provided to customers outside Newco footprint). It is anticipated that the Newco result should take the best of SPP and MISO, including possibly the stakeholder input model (sectors, balanced sectors, etc.). Currently MISO has no regional reliability functions and no provision to assume those functions. Cost separation of the regional reliability functions would have to be investigated. NERC regions and their members will determine the boundaries of NERC regional reliability councils. Note that Entergy is in the SERC reliability region and MISO members are in MAPP, MAIN, ECAR, and SPP.

This analysis must include the “obligation” SPP has to transmission owners for expenses incurred as start-up costs of SPP. Under MISO agreements, non-transmission owning members pay an additional cost that would need to be considered in the consolidation. and This
provision will need to be revisited.

Also, the Board did request a negotiating committee for the governance, which has been formed and consists of Tom McDaniel, Harry Skilton, and John Oxendine from SPP, and Bill Vititoe, Bill Albertenni, and Jim Young from MISO. The Board directed SPP Staff to develop the definitive documents for Board consideration.

No additional SPP staff activity is anticipated on the rehearing request pending FERC action and subsequent Board action.

| Harry Dawson OMPA | Pursuant to yesterday's board meeting, OMPA's comments on the draft term sheet are included herein. Before getting to the specific comments, however, I will say that I am (once again) concerned with our linear process we are going through. We do not (discernable to me) yet have a fallback plan if discussions with MISO do not conclude successfully, mediation with FERC having been rejected yesterday, and Mike Small's direction on the application for rehearing when we get the tolling order (doubt we will get an outright rejection) undiscussed. We are in a very reactionary mode; I would like to see the board get proactive, what do we want to be when we grow up? Comments of the distributed draft of the combination LOI. |
| Dave Christiano CUS | I agree with Tom McDaniel's assessment that we should not fear mediation. Even the southeast ALJ has acknowledged that we bring a lot of assets to the table. |
| Richard Verret AEP | The Directors of the SPP have a fiduciary obligation to its members not to take actions that would adversely affect them. Therefore, the SPP should be examining in parallel, alternatives to a SPP/MISO combination. The alternatives include but may not be limited to:

1. combination with the Alliance RTO;
2. combination with a southeastern RTO developed as the result of the ongoing FERC mediation;
3. dissolution of the SPP, thereby permitting SPP members to choose an RTO of their liking; or
4. simply to challenge the FERC's rejection of the SPP RTO proposal and FERC's jurisdiction to require transmission owners to join RTOs.

The SPP Staff should be required to perform a cost/benefit analysis of pursuing these alternatives as well as the SPP/MISO combination. Such analysis should include an evaluation of the transaction and operational costs as well as delay associated with transitioning to the new structure and the operating costs associated with combined...
operations for each alternative studied. Any agreement relating to
SPP's combining with another organization to form a larger regional
organization must provide that any SPP member would be free to
decide not to participate in the new organization, and could thereby
limit its obligations to the SPP and the new organization to its fair
share of liabilities incurred prior to the date of notice of withdrawal.

<table>
<thead>
<tr>
<th>Richard Verret</th>
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<tr>
<td>AEP</td>
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<td>Given the abrupt and unanticipated change in FERC RTO policy reflected in its July 12 orders, the Board ought immediately act to make clear that each SPP member is free to join the RTO of its choosing without having to give the withdrawal notice required by Section 4.1.1, which would tie members to the SPP at least through October 31, 2002, and thereby make them responsible for costs incurred in transitioning the SPP to a larger organization. The Board should also recognize that, in the present circumstances, each SPP member should be allowed to exercise a regulatory out within a reasonable period of time after the FERC's July 12 order, which changed the bargain entered into by SPP and its members.</td>
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<th>Frederick Ochsenhirt</th>
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<td>ETxC</td>
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<td>The East Texas Cooperatives generally support an expanded RTO including the SPP footprint, and have actively participated in the ongoing FERC mediation effort directed toward development of a single RTO for the Southeast U.S. While we understand that developments in the mediation process have forced the SPP to once again engage the Midwest ISO in merger discussions, we do not believe that the SPP should abandon efforts to develop an RTO in the Southeast that includes at least some of the SPP members. The mediation process could produce a viable RTO for a large geographic region that encompasses the facilities, load and natural markets for many of the current SPP members. Thus, we don’t think that discussions with the participants in the Southeast RTO mediation process should not be abandoned.</td>
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<tr>
<th>Dick Dixon</th>
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<td>WRI</td>
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<td>Assuming unsuccessful negotiations, SPP should be prepared to request FERC assistance for a merger (Midwest mediation).</td>
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<th>Kim Casey</th>
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<td>Dynegy</td>
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<tr>
<td>We agree with AEP that withdrawing members should be permitted to accelerate their withdrawal from the RTO and not be penalized by the imposition of additional costs that would otherwise be incurred for the start-up of the new or merged RTO during the one year period following notice of withdrawal.</td>
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<tr>
<th>Harry Dawson</th>
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<td>OMPA</td>
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<td>Need to address what happens to the residual members (who do not move with SPP to MISO).</td>
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<tr>
<th>Bill Dowling</th>
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<td>MWE</td>
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<td>This assumes that all current transmission-owning members of SPP would automatically become members of Newco, simply by assignment of the currently effective Membership Agreements. In</td>
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<td>J. M. Shafer</td>
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<tr>
<td>Rick Henley</td>
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<tr>
<td>CWL-J</td>
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<tr>
<td>Jess Totten</td>
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<td>PUCT</td>
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competition under Texas Senate Bill 7. In the aftermath of the FERC's decision in the SPP's RTO application, the SPP Staff has recommended that the SPP join the Midwest Independent System Operator. At the same time, the SPP has filed a motion for rehearing in the SPP RTO case, arguing that the FERC should have approved the SPP-Entergy partnership.

I am concerned that the SPP may be making a hasty decision to abandon its partnership with Entergy to pursue a partnership with MISO. Areas of particular concern are:

* The natural markets in the SPP region;
* The uncertainty about RTO formation in the Southeast and Midwest; and
* The desirability of a single wholesale market in East Texas, to serve as a foundation for a vibrant competitive retail market.

The Staff and Board of the SPP believed that a partnership with Entergy made sense, and the SPP continues to argue before the FERC that its natural market is the SPP-Entergy area. If this is the natural market, it should not be split.

Obviously, the mediation efforts underway in Washington concerning a Southeastern RTO leave some doubt about whether a viable RTO proposal will emerge, and about whether the utilities in the area will support an RTO. Similar problems exist with respect to the Midwest. While there are two Midwestern RTO organizations that have been created and approved by the FERC, the fact that there are two organizations is the source of uncertainty. It appears that the FERC intends that there be no more than three RTOs in the Eastern Interconnection, one each in the Northeast, Southeast, and Midwest. If this is the case, then the FERC is likely at some point to require MISO and the Alliance to merge and to incorporate other unaffiliated utilities in the Midwest. It seems likely that the Midwest faces a period of uncertainty about the scope and configuration of its RTOs and significant management attention to merging, incorporating new members, and revising operating and market rules. One of the questions that needs to be considered is whether a partnership between SPP and MISO affords greater certainty than a partnership with Entergy, whether Entergy is a member of an Southeastern RTO or not.

The law that mandates retail competition in Texas, Senate Bill 7, requires the establishment of independent organizations to ensure access to the transmission system, maintain a reliable electric network, settle wholesale accounts, and manage the information system that allows customers to switch providers. For the Entergy
and AEP areas of East Texas, the SPP-Entergy partnership would have met the transmission-access, reliability, and settlement requirements, and ERCOT would have met the switching requirements. Under this proposal, there would have been a single market in East Texas. There are a number of advantages to this partnership for competitors in the Texas market: a single transmission tariff for wholesale power, no pancaking of transmission rates between Entergy and AEP, a broader market for ancillary services and balancing energy, and a single system for reserving and buying transmission service. This would have made for a more vibrant wholesale market and lower barriers to retail electric providers to enter the retail market in East Texas. If SPP joins a Midwestern RTO and Entergy a Southeastern RTO, there will be two smaller wholesale markets in East Texas and additional burdens for retail electric providers that seek to compete there.

It is obviously not at all clear what will happen in either the Midwest or Southeast, and it may later appear that the only viable choice for the SPP is to join the MISO. For now, however, it appears that the better course is to avoid making a commitment before the completion of the Southeast mediation efforts. If the mediations in the Southeast are successful and a viable RTO proposal emerges, joining a Southeastern RTO may be the best option for the SPP. If those mediation efforts fail, then FERC may be more receptive to the SPP-Entergy RTO proposal.

**RESPONSE**

SPP participated in the SE mediation and has no indication as to what FERC will do in the Midwest. The Board directed SPP Staff to explore both options as well as a super-regional RTO. Each of those alternatives is still active. The issue is what is best for SPP members. The SE mediation has not produced definitive agreement (who will accept, what will be the end state, when the SE will be formed, etc.). The MISO term sheet represents a more positive step of agreement to favorable terms. Any agreement with MISO similar to the MISO/ARTO solution would be up to FERC scrutiny and indications are that it would take a lot of convincing that a seams agreement was more beneficial than merger. Merging with Alliance RTO is not a high priority for them as they are intent on meeting the 12/15/01 deadline for RTO operation. SPP Staff has made repeated proposals to provide services in the formation of the ARTO and several recent attempts to contact the ARTO about combinations. Each of these proposals and attempts has been rejected. There are no other parties that would meet the most recent FERC direction of really large RTOs.
SPP members still have the option at the end of the day to request mediation within the Midwest.

At present the only direction we have from FERC is a clear preference for one Midwest RTO and they anticipate that SPP could be a better fit in that RTO.

At present any SPP member has a limit to their obligations based on the current membership agreement. The Directors of the SPP have a fiduciary obligation to its members not to take actions that would adversely affect SPP. The Board can discuss if there are other terms for membership withdrawal (including the affects on the financial term sheet for the Market Settlement System). Additionally SPP has submitted a request for rehearing on FERC’s rejection of the SPP RTO. FERC actions on July 12 did nothing to change the current legal relationships of SPP and its members.

<table>
<thead>
<tr>
<th>Richard Spring</th>
<th>Definition of Newco, ITC, and Transco is needed.</th>
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<tbody>
<tr>
<td>Bill Dowling</td>
<td>In the first section containing the “Whereas” statements, the second statement should be modified to define the term NEWCO, which is used throughout the document. An example of such a statement would be: Whereas, the parties are desirous of exploring the basis upon which a possible combination or other business transaction involving the parties might take place, such combination or transaction resulting in the formation of a new independent transmission operator (“Newco”),</td>
</tr>
<tr>
<td>Mike Deihl</td>
<td>“ITC” should be defined (as distinguished from a Transco) so there is no misunderstanding what this is.</td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>“ITC” should be defined (as distinguished from a Transco) so there is no mis-understanding what this is.</td>
</tr>
<tr>
<td>OCC</td>
<td>Fourth Sentence – ITC - independent transmission co or investment tax credit?</td>
</tr>
<tr>
<td>Kim Casey</td>
<td>Do you define an ITC as any transmission owner that has not spun its transmission assets off into a Transco? If so, then define ITC somewhat.</td>
</tr>
<tr>
<td>Bill Dowling</td>
<td>Newco – New company formed from the combination of SPP, Inc. and MISO, Inc. Each ITC (“Independent Transmission Company”) and Transco is defined by the provisions of the agreements that they have with RTOs and FERC’s action on those agreements.</td>
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</table>
Oklahoma Gas and Electric Company (OG&E) believes that the transition to NEWCO should be made as expeditiously as possible. It is important that the new organization not maintain vestiges of the past; rather, reasonable transition provisions should be put in place to permit expeditious implementation of the new alliance. Existing talent should be integrated into NEWCO to the fullest extent possible. The Term Sheet should emphasize the movement to the end state rather than dwelling unnecessarily on transition issues. The new organization should be structured so as to achieve fair treatment of personnel and assets in the transition.

RESPONSE
Noted.

1. NATURE OF PROPOSED COMBINATION

Assets and Liabilities of the MISO and SPP would be contributed, transferred to or assumed by Newco at book value. The specific form of the transfer will be determined with regard to tax and accounting matters. The remaining MISO and SPP transmission-owning members would be transmission-owning members in Newco. Any Memoranda of understanding, contracts or coordination agreement with transmission owners or ITC arrangements would be assigned by SPP or the MISO to Newco, with consents as required. SPP as a regional Reliability Council would continue in existence unchanged by the transaction. Non-transmission owner members of the MISO and SPP would become non-transmission-owning members of NEWCO without additional cost to them.

A new sentence should be added at the end of this paragraph providing that SPP transmission owning members shall have the right to participate in any Transco within the Newco footprint.

RESPONSE
Noted.

The Term Sheet provides that any memorandum of understanding, contracts or coordination agreement with transmission owners would be assigned by SPP to NEWCO, with consents as required. The section of the SPP Membership Agreement relating to successors and assigns (Section 8.2 in the prior form of Membership Agreement and Section 9.2 in the form of RTO Membership Agreement) provides generally that the Agreement "shall inure to the benefit of, and be binding upon Members, their respective successors and assigns permitted hereunder." That section also expressly permits SPP members to assign their interests in the Membership Agreement with the prior approval of the SPP Board of Directors, which is not unreasonably to withhold such approval, and without such approval if the assignment is to a successor in the operation of a transmission owning member's "Tariff Facilities" if the successor becomes a transmission owner under the Agreement. Notably, the "successor
and assigns” section does not expressly contemplate assignment of a Membership Agreement by the SPP. Hence, SPP would have to obtain consent to assignment from each SPP member that is party to a Membership Agreement.

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<tr>
<td>Shantha Varahan</td>
<td>Assignment by SPP or MISO of contracts or agreements with transmission owners or ITC deals may leave some transmission contracts unassigned. SPP and MISO seem to hold some discretion as to what may be assigned. Also, there is a prerequisite that consent be obtained. What if consent is not obtained?</td>
</tr>
<tr>
<td>OCC</td>
<td>Need to address what happens to the residual members (who do not move with SPP to MISO). Explain the relationship with such companies as Entergy, Associated Electric Coop and others that operate within the SPP footprint.</td>
</tr>
<tr>
<td>J. M. Shafer</td>
<td>Should Transmission Owners be given the opportunity to accept new membership agreement with the merged organization instead of unilaterally having them agree to the terms as the organizations merge?</td>
</tr>
<tr>
<td>WFEC</td>
<td>What are the exit terms from the merged entity??</td>
</tr>
<tr>
<td>J. M. Shafer</td>
<td>Next to Last Sentence – SPP regional reliability - Why does this need to be agreed to in any merger agreement? This is not consistent with the pending NERC legislation.</td>
</tr>
<tr>
<td>Dynegy</td>
<td>Assignments would not occur without Board authorization and consents are contemplated. Entergy and Associated Electric Coop are not within the SPP tariff and Associated Electric Coop is not a member of SPP</td>
</tr>
</tbody>
</table>

**RESPONSE**

<table>
<thead>
<tr>
<th>Name</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kim Casey</td>
<td>Third Sentence – What does remaining mean? “remaining” after what?</td>
</tr>
<tr>
<td>Dynegy</td>
<td>Noted - “remaining” should be deleted.</td>
</tr>
</tbody>
</table>

### 2. FORM OF NEWCO

Delaware non-stock, not-for-profit corporation, with possible for-profit subsidiaries.

### 3. BUSINESS OF NEWCO

Newco would be in the business of providing RTO/FERC Order 2000 services on a bundled and on an unbundled or menu basis and would be the RTO covering the MISO and SPP regions. As the one RTO over the combined region, Newco would be responsible for all FERC Order 2000 attributes and functions. Customers would be able...
to take differing levels of service depending upon FERC approval of such customer as an ITC or Transco within the footprint. Transmission service within the footprint would be offered under a single tariff. Newco would also offer services on a commercial contract basis. Newco would act as security coordinator for the footprint of its transmission owning members and to the degree successful for the area of its contract customers. The current MISO Appendix I, the proposed SPP/Entergy MOU or an appropriate substitute sufficient to accommodate the business needs of Transcos or ITCs, would be available to forming Transcos or ITCs.

<table>
<thead>
<tr>
<th>Mike Deihl</th>
<th>This section implies that a customer of NEWCO must be either an ITC or Transco. Why?</th>
</tr>
</thead>
<tbody>
<tr>
<td>SWPA</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Bill Dowling</th>
<th>The third sentence provides that “Customers would be able to take differing levels of service depending upon FERC approval of such customer as an ITC or Transco within the footprint.” Depending upon the definition of ITC in particular, this sentence may or may not be sufficiently inclusive. As to the term “Customer”, is this distinct from a “Member”? If so, then say so somewhere. This sentence needs to provide for transmission owners’ procurement of the services necessary to operate transmission facilities under the Newco.</th>
</tr>
</thead>
<tbody>
<tr>
<td>MWE</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Shantha Varahan</th>
<th>Must a customer of Newco be either an ITC or a Transco?</th>
</tr>
</thead>
<tbody>
<tr>
<td>OCC</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>RESPONSE</th>
<th>Customers in this sense are transmission owners who purchase any RTO services from Newco (not transmission service customers).</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Kim Casey</th>
<th>First Sentence – add “existing” before “MISO and SPP”.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dynegy</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>RESPONSE</th>
<th>Noted.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Kim Casey</th>
<th>Last Sentence – Change “would” to “and acceptable to FERC will” before “be available”.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dynegy</td>
<td></td>
</tr>
</tbody>
</table>

| RESPONSE            | Noted.                                                                               |

### 4. TARIFF

The Newco will maintain and administer individual tariffs for the SPP and MISO regions for a period necessary to provide for a smooth transition to a single tariff, though there will be one-stop shopping for the customers throughout the transition. Each of the two regions, as specified in their existing agreements, will control pricing and other transitional issues such as what load is under the tariff and grandfathering.

The other terms such as generation interconnection procedures, scheduling and response times, and penalties will be standardized so that they are the same under both tariffs unless differences can be justified. Also, the regional tariffs will need to maintain certain
differences with regard to retail service as these types of provisions will vary from state to state.

Aside from pricing, load under tariff, grandfathering, retail issues and other issues that affect recovery of transmission revenue requirements, any tariff changes shall be subject to the ultimate approval of Newco.

Revenue distribution methods involving recovery of transmission revenue requirements will not be changed by this new structure. The other ancillary services schedules and loss schedules will be standardized. As to cost adders to recover the costs of Newco operations, there will be only one cost adder. It will be collected at the Newco level to allow full recovery of costs for all Newco operations including the administration of two tariffs during the transition. The Newco cost adder will be similar to the MISO cost adder that contains a 15-cent cap and a deferral mechanism as in the MISO Open Access Transmission Tariff (“OATT”) schedule 10. If FERC finds in the pending MISO case concerning application of Schedule 10 that all load, including bundled load should pay the adder, then the Newco adder shall be charged on all load within MISO/SPP. Rate pancaking between the former SPP and former MISO will be eliminated.

Newco may use a rate charge like the one outlined in the MISO-ARTO settlement to govern transmission pricing over SPP-MISO and to limit losses from the elimination of rate pancaking.

Newco will file a single tariff by December 31, 2002.

<table>
<thead>
<tr>
<th>Harry Dawson</th>
<th>In # 4, why would we have separate tariff's? The license plate tariff apparently is on its way out, why not make the break.</th>
</tr>
</thead>
<tbody>
<tr>
<td>OMPA</td>
<td></td>
</tr>
<tr>
<td>Mike Deihl</td>
<td>For the SWPA to participate under current statutory requirements, we will need to retain the current Federal hydropower exemption.</td>
</tr>
<tr>
<td>SWPA</td>
<td></td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>Why would Newco administer 2 separate tariffs for SPP and MISO?</td>
</tr>
<tr>
<td>OCC</td>
<td></td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>The tariffs can be different as to pricing and “other transitional issues”. These are not identified. What are the other transitional issues? (Two examples are provided, what load is under the tariff and grandfathering.) Other terms will be standardized. But those are not identified specifically either. Examples are given, such as generation interconnection procedures, scheduling and response times and penalties. Is this type of selection appropriate? Does it not remove some power from the Newco RTO entity? Also, there is reference in this section as to differences in terms must be &quot;justified&quot; but no mention to whom the justification must be made (Newco BOD</td>
</tr>
<tr>
<td>Name</td>
<td>Comment</td>
</tr>
<tr>
<td>--------------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Shantha Varahan OCC</td>
<td>Why would Newco administer 2 separate tariffs for SPP and MISO?</td>
</tr>
<tr>
<td>Frederick Ochsenhirt ETxC</td>
<td>There are certain threshold issues that should be addressed in preliminary discussions with the MISO. First, the combined RTO (designated “Newco” in the Term Sheet) must treat all transmission owners fairly, applying a single consistent standard to all transmission owners for determining which transmission facilities may be transferred to the RTO, pricing of service over such facilities and allocation of transmission revenue requirements. The East Texas Cooperatives will not only not support, but will actively oppose, any SPP-MISO combination that fails to treat all transmission owners equally in all respects. Therefore, it is not acceptable for Newco to simply maintain existing SPP and MISO tariffs if such tariffs do not treat all transmission owners fairly.</td>
</tr>
<tr>
<td>Frederick Ochsenhirt ETxC</td>
<td>Similarly, Order No. 2000 requires that an RTO have exclusive rights to file for tariff changes under Section 205 of the Federal Power Act. Therefore, the language in the Term Sheet excluding “pricing, load under tariff, grandfathering, retail issues and other issues that affect recovery of transmission revenue requirements” from tariff changes under the exclusive control of Newco conflicts with Order No. 2000. It may be reasonable to start with the existing tariffs in developing the initial Newco tariff, but Newco must be free to propose to FERC any rate change (with the possible exception of transmission revenue requirements for Transmission Owners while license plate rates are in effect).</td>
</tr>
<tr>
<td>Brenda Blundell OGE</td>
<td>NEWCO should go to a single rate throughout the NEWCO footprint at the time NEWCO is recognized as an RTO by the FERC. Grandfathered contracts could be “bought out” as a part of initial start-up costs, or a special Transmission Owner Task Force could be established upon implementation of the NEWCO RTO to review existing grandfathered contracts and report to the Board of NEWCO concerning the status of those agreements and a proposal to eliminate the grandfathered contracts by a date certain where possible within a reasonable period of time after the NEWCO RTO becomes operational.</td>
</tr>
<tr>
<td>Mike Deihl SWPA</td>
<td>In the third sentence, there is reference to differences in terms being “justified” but no mention to whom the justification must be made (NEWCO BOD or who?).</td>
</tr>
</tbody>
</table>
| Kim Casey                | First sentence – Change “can be justified” to “are justified to the
<table>
<thead>
<tr>
<th>Name</th>
<th>Company</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bill Dowling</td>
<td>MWE</td>
<td>The fifth sentence provides: “Aside from pricing, load under tariff, grandfathering, retail issues and other issues that affect recovery of transmission revenue requirements, any tariff changes shall be subject to the ultimate approval of Newco.” Does this refer to changes to the individual SPP or MISO tariffs during the transition phase? If so, make this clearer. If not, then clearly state that this refers to the ultimate Newco tariff.</td>
</tr>
<tr>
<td>Richard Verret</td>
<td>AEP</td>
<td>Finally, the Term Sheet provides that the Newco Board will have ultimate authority over tariff changes other than those that affect recovery of transmission revenue requirements. The Term Sheet should be modified to make clear what rights Transmission Owners, or other Newco participants for that matter, will have to propose or object to such tariff changes.</td>
</tr>
<tr>
<td>Dick Dixon</td>
<td>WRI</td>
<td>There is a statement in this paragraph that revenue distribution within the SPP or MISO will not change under Newco. If this means that SPP transmission owners will continue to go uncompensated for loop flows from MISO/MAPP transactions, it is unacceptable.</td>
</tr>
<tr>
<td>Bill Dowling</td>
<td>MWE</td>
<td>The sixth sentence states “Revenue distribution methods involving recovery of transmission revenue requirements will not be changed by this new structure.” Again, does this refer to the transition period and the individual SPP and MISO tariffs, or the combined Newco tariff? This should be clarified.</td>
</tr>
<tr>
<td>Kim Casey</td>
<td>Dynegy</td>
<td>There should be some kind of limit on this prohibition in changing revenue distribution methods, e.g. until the single Newco tariff is filed on December 31, 2002. Revenue distribution for?</td>
</tr>
<tr>
<td>Dick Dixon</td>
<td>WRI</td>
<td>This paragraph is not clear as to what will become of SPP’s Schedule 1 charge. Will it be eliminated?</td>
</tr>
<tr>
<td>Harry Dawson</td>
<td>OMPA</td>
<td>How will the adder (all load, or just tariff load) be handled.</td>
</tr>
<tr>
<td>Dave Christiano</td>
<td>CUS</td>
<td>I'm not familiar with the MIS/ARTO settlement. What is the meaning of the next to last sentence? It is not clear what provisions of this section pertain to the transition period and which pertain to the period when the two tariffs are merged. To get FERC RTO blessing, pancaking would have to be eliminated in the entire RTO region presumably including the Alliance (not just SPP-MISO).</td>
</tr>
</tbody>
</table>
| Dick Dixon     | WRI     | We need additional discussion of how the MISO/ARTO super regional tariff will work for the SPP. At a minimum, we need language that commits Newco to meeting the transmission owners’
<table>
<thead>
<tr>
<th>Name</th>
<th>Organization</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bill Dowling</td>
<td>MWE</td>
<td>Should this paragraph address the combined super-regional transmission rates available to members of MISO and ARTO under their settlement agreement? While this agreement cannot bind ARTO to anything, since it is not a party to this agreement, shouldn’t this document clearly state that the intention is to provide all members of Newco with access to the super-regional transmission rate that covers ARTO as well?</td>
</tr>
<tr>
<td>Mike Deihl</td>
<td>SWPA</td>
<td>There is reference to the MISO-ARTO settlement agreement. Southwestern is not familiar with the specific terms of this agreement. Southwestern believes this should be expanded/clarified so current SPP members know what charge they are agreeing to.</td>
</tr>
<tr>
<td>Richard Verret</td>
<td>AEP</td>
<td>The Term Sheet suggests that the combined organization may use a rate charge like that provided for in the MISO-ARTO settlement to limit losses from the elimination of rate pancaking. The use of such a rate charge must be an absolute condition to consolidation.</td>
</tr>
<tr>
<td>Frederick</td>
<td>ETxC</td>
<td>In negotiating any combination with MISO, the SPP should remain mindful of existing RTO operations and relationships in the Midwest. MISO and the Alliance RTO (“ARTO”) are parties to an Inter-RTO Coordination Agreement (“IRCA”) resulting from the settlement of a number of FERC proceedings, including the request of certain MISO members to withdraw from MISO in order to join ARTO. Pursuant to the IRCA, all MISO and ARTO members joining prior to February 28, 2001 form an RTO Super Region. Customers taking service in this Super Region pay a single, non-pancaked transmission rate. Members of the SPP should obtain access to this Super Regional rate as of Day One of SPP/MISO operations. In addition, the SPP and MISO should commit to a good faith effort to expand the Super Region to include the SPP, in addition to MISO and ARTO.</td>
</tr>
<tr>
<td>Dave Christiano</td>
<td>CUS</td>
<td>We need transmission zones to be maintained.</td>
</tr>
<tr>
<td>Dick Dixon</td>
<td>WRI</td>
<td>What will become of the SPP tariff once Newco files a single tariff by December 31, 2002? How will transactions granted under the SPP tariff be handled once Newco’s new tariff becomes effective? Will they be grandfathered or will they converted to the new tariff?</td>
</tr>
<tr>
<td>Mike Deihl</td>
<td>SWPA</td>
<td>What happens to transactions that are executed under one of the existing tariffs (SPP or MISO), but are concluded after the new tariff is in place?</td>
</tr>
<tr>
<td>Richard Verret</td>
<td></td>
<td>The Term Sheet contemplates that the combined organization will file...</td>
</tr>
</tbody>
</table>
AEP | a single tariff by December 31, 2002. If this means a single system rate for the combined SPP/MISO area, the economic implications of such a rate for *each* transmission owner need to be explored and explained, including how the rate will be designed. Also, some explanation should be provided as to how revenues collected under a single system rate would be allocated among transmission owners. Finally, the tariff should provide for a transition period during which agreed-upon rates remain in effect, as is the case in the SPP.

Shantha Varahan OCC | What happens to transactions that are executed under one of the existing tariffs (SPP or MISO), but are concluded after the new tariff is in place?

Shantha Varahan OCC | The Newco is to file a single tariff by December 31, 2002. Does eliminate the individual tariffs of SPP and MISO mentioned above? Would the wholesale tariff be one and the state by state differences be reflected differently?

Frederick Ochsenhirt ETxC | A preliminary analysis of the draft Term Sheet indicates that several provisions must be modified if the SPP and MISO intend that Newco be the sole Commission-approved RTO for the region. Order No. 2000 requires that an RTO administer a single RTO tariff for the region. Therefore, the Term Sheet’s requirement that Newco maintain separate SPP and MISO tariffs through December 31, 2002 is not acceptable if Newco intends to commence operations before January 1, 2003. Inasmuch as Order No. 2000 also requires RTOs to be operational by December 15, 2001 (and neither the SPP nor MISO has been approved as a stand-alone RTO), it is likely that a single Newco OATT will be necessary substantially sooner than January 2003.

J. M. Shafer WFEC | Is the new organization committed to full cost recovery for transmission owners?

Richard Spring KCPL | Treatment of grandfathered agreements and transmission service reserved the SPP tariff must be defined. I would propose that grandfathered agreements go until they terminate and network service under individual OATT tariffs until the state deregulates retail customers. Transition from the SPP Regional tariff and how transmission reservations under the SPP reservations will be handled must be defined.

Kim Casey Dynegy | First sentence – Change sentence to read “No later than December 31, 2002, Newco will file a single tariff that is applicable to all transmission service in the Newco region.”

Rick Henley | How sill the new single tariff be developed - by who?
CWL-J

**RESPONSE**

The intent of the Term Sheet was to provide a transition between the present two tariffs to one tariff. The expectation was that the combination and resulting benefits could be achieved faster than the negotiation and acceptance (including FERC) of a single tariff. Newco would have exclusive right to modify each of the existing tariffs. Some of the terms will have to be standardized quickly based on the expectation that FERC would only allow some in transition (including elimination of rate pancaking but including a mechanism to maintain revenue requirement using something like the MISO/ARTO settlement). There will be a number of issues (including existing service) to be resolved that are highlighted in these comments.

---

**Kim Casey**  
**Dynegy**

Add second sentence – The transition to a single tariff will occur upon FERC’s approval of the Newco tariff to be filed December 31, 2002.

**RESPONSE**

This is already at the end of this section.

---

**Kim Casey**  
**Dynegy**

First sentence – Strike “The” before “other”.

**RESPONSE**

Noted.

---

**Shantha Varahan**  
**OCC**

There is reference to the MISO/ARTO settlement agreement. Where is it available for review?

**Kim Casey**  
**Dynegy**

First sentence – Add after “settlement”, “accepted by FERC in___________, Docket No.__________on ___________. CITE,”.

**RESPONSE**

This was filed and accepted at FERC. **CITE ER01-123-000**

---

**5. LOCATIONS**  
**Indianapolis/Carmel, Little Rock, Minneapolis/St.Paul**

**Bill Dowling**  
**MWE**

I would suggest modification of this pseudo-paragraph. I would think that our ultimate goal would be to consolidate the offices of Newco into a single location, to minimize our investment in buildings and infrastructure. (It is possible that there will be some satellite/regional operating centers, but I think we would want to look at this pretty closely.) Perhaps this paragraph should read something like: The offices of Newco will be established in either
Indianapolis/Carmel, Little Rock, or Minneapolis/St.Paul, or some combination thereof.

RESPONSE
Noted.

6. FUNCTIONS PER LOCATION
Recommendations to the Board of Directors regarding facilities, locations, placement of functions, and numbers of personnel would need to be made based upon the development and analysis of alternatives. We would suggest the formation of a team (or teams) to develop these.
7. BOARD AND GOVERNANCE STRUCTURES
An independent Board will govern Newco and will consist of eight independent members of the MISO board, including the President of the MISO as one of the eight, and five independent board members from SPP, including the President of SPP as one of the five. [If the load of either SPP or MISO significantly changes prior to closing of the combination, then the number of board positions taken from each SPP and MISO will be re-addressed.] It is the intent of the parties that the size of the Newco board be reduced to less than ten members over the ensuing five years.

The non-officer board members will be assigned to three groups, of approximately equal size, and the terms of each group will be staggered with the first group serving a term of two years, group two serving a term of three years and group three serving a term of four years.

A Stakeholder Advisory Committee (similar to the MISO Advisory Committee) designed with a balanced sector voting process to ensure no undue influence by any one sector, will make recommendations (including majority and minority reports) directly to the Board.

The Stakeholder Advisory Committee will have strong meaningful input that reflects the interests of all stakeholders into the decisions of the Board on matters particularly related to the safe and reliable operation of the interconnection (technical matters), facilitate a robust non-discriminatory energy market, budgets, insuring that no member of groups of members is able to exercise undue influence and incorporates the regions of the original MISO, Mid-continent Area Power Pool (“MAPP”) and SPP.

Each category will have three representatives, one each from the original MISO, SPP and MAPP regions. The representatives will be elected by their constituent groups and each representative will be entitled to one vote on matters the Stakeholder Committee requires votes, should certain constituent groups desire non-voting status that shall be allowed at their discretion. The Stakeholder Committee will have a permanent place on the agenda of the Board of Directors meeting to address the Board at all of its meetings. At least two members of the Board and the President shall attend all Stakeholder Committee meetings.

A committee of the Stakeholder Committee will review with Newco management budgets and major capital projects and expenditures prior to submission to the Board for approval. The Stakeholder Committee may form other committees to address other areas of interest to the participants, which may include but not be limited to policy, markets, system operations, billing and settlements, congestion management or any other broad areas that affect Newco.
Board meetings of Newco will be open to any participants. Newco’s Board will only meet in executive session to address certain items, such as (a) personnel-related information; (b) information subject to a legal privilege; (c) information that is confidential to third parties; (d) business transactions or combinations; (e) consideration of the sale or purchase of securities, investments, or investment contracts; (f) strategy and negotiation sessions in connection with a collective bargaining agreement; (g) discussion of emergency and security procedures; (h) consideration of matters classified as confidential by federal or state law; (i) protection of intellectual property; and (j) discussion of proceedings by any Alternate Dispute Resolution Committee, each as described in the By-laws of the Midwest ISO.

A Transmission Owners Committee will also be formed.

<table>
<thead>
<tr>
<th>Name</th>
<th>Comment</th>
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<tbody>
<tr>
<td>Mike Deihl SWPA</td>
<td>In the last sentence of the first paragraph, define what “non-officer board members” represents.</td>
</tr>
<tr>
<td>Shantha Varahan OCC</td>
<td>In the last sentence of the first paragraph, define what &quot;non-officer board members&quot; represents.</td>
</tr>
<tr>
<td>Kim Casey Dynegy</td>
<td>Strike “non-officer”.</td>
</tr>
<tr>
<td>RESPONSE</td>
<td>This was intended to reflect the board members that were elected not the two presidents.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Name</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mike Deihl SWPA</td>
<td>Second sentence, second paragraph; reference to “interconnection” should read “transmission system”. Interconnection is an entirely different meaning. The last sentence in that paragraph uses the word “original”. We would suggest this be changed to “existing”. The original footprint of an organization may be different from what they have today. This same suggestion applies to the first sentence of the next paragraph.</td>
</tr>
<tr>
<td>Shantha Varahan OCC</td>
<td>Second sentence, second paragraph; reference to &quot;interconnection&quot;. Should it read &quot;transmission system&quot;?</td>
</tr>
<tr>
<td>Shantha Varahan OCC</td>
<td>Define the word &quot;original&quot; which is used in the context “…and incorporates the regions of the original MISO, Mid-content Area Power Pool (“MAPP”) and SPP.” Is the original different or the same today?</td>
</tr>
<tr>
<td>Kim Casey Dynegy</td>
<td>Change “interconnection” to “transmission system”.</td>
</tr>
<tr>
<td>Kim Casey Dynegy</td>
<td>Change “existing” to “original”.</td>
</tr>
<tr>
<td>RESPONSE</td>
<td>Noted.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Name</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bill Dowling</td>
<td>In the second paragraph, second to last line, repair the typographical</td>
</tr>
</tbody>
</table>
8. ASSETS AND LIABILITIES

Valuation of assets and liabilities will be at book value.

9. UTILIZATION OF FACILITIES AND EMPLOYEES

It is the intent of the MISO and of SPP that all existing facilities and employees of the two entities be fully utilized and that efforts be made to reduce the number of needed new employees or systems to recognize the efficiencies of this combination. The MISO and SPP intend that the Newco be staffed initially by employees of the MISO and SPP who then become employees of Newco, unless sufficient qualified employees are not available for transfer, in which case Newco may hire others. Severance, if any, for employees of MISO or SPP not employed with Newco shall be per the terms of MISO and SPP severance policies.

Kim Casey Dynegy

Last sentence – Change “severance” to “employment”.

RESPONSE Noted.
10. PERSONNEL

The current officers’ contracts will remain in effect. The Board of Newco will determine actual appointment of individuals to specific officer positions.

| Mike Deihl | What positions are represented by the “Officers”? |
| SWPA       |                                                 |
| Shantha Varahan | What positions are the "Officers”?? |
| OCC        |                                                 |

**RESPONSE**

These would be the present officers of each entity. Currently for SPP they are the President and Corporate Secretary. Currently for MISO they are the CEO, COO, CIO, CFO, and General Counsel.

| Kim Casey | Again, this provision must be consistent with the SPP Board’s vote of August 13, 2001. |
| Dynegy    |                                                                                  |

**RESPONSE**

Noted.

11. REGULATORY ACTIONS

The MISO and SPP agree to consider the joint submittal and support of a petition for declaratory order to the FERC seeking an order stating that this combination satisfies the scope and configuration and governance requirements of Order No. 2000. The MISO and SPP agree to share the costs of the filing fee. This petition, if a joint decision is made to file, shall be submitted within twenty-one days after the approval of both Boards of Directors of MISO and SPP.

| Dick Dixon | This paragraph indicates that a filing with FERC regarding scope and configuration is optional. However, paragraph 14 requires FERC approval before completing the transaction. Paragraph 11 should also reflect that requirement. |
| WRI       |                                                                                     |

**RESPONSE**

Noted.

| Dick Dixon | This paragraph indicates that a filing with FERC regarding scope and configuration is optional. However, paragraph 14 requires FERC approval before completing the transaction. Paragraph 11 should also reflect that requirement. |
| WRI       |                                                                                     |

**RESPONSE**

Noted.

| Bill Dowling | While this paragraph establishes that the Petition for Declaratory Order will be filed within twenty-one days of approval by the Boards of both MISO and SPP, it does not define a time frame for such |
| MWE        |                                                                                     |
approval. Looking ahead to paragraph 14, two dates are suggested therein: (1) approval of a final term sheet, and (2) definitive documentation. Where does the Petition fit into this process? This should be clarified in either paragraph 11 or 14.

<table>
<thead>
<tr>
<th>RESPONSE</th>
<th>Noted.</th>
</tr>
</thead>
</table>

Richard Verret  
AEP  
The Term Sheet contemplates the joint submittal of a Petition for Declaratory Order seeking a FERC finding that the combination would satisfy the scope, configuration and Governance requirements of Order No. 2000. It is unclear why the combination needs the approval of the FERC.

<table>
<thead>
<tr>
<th>RESPONSE</th>
<th>This is contemplated to press FERC for action on the scope and configuration of the combined organization.</th>
</tr>
</thead>
</table>

Shantha Varahan  
OCC  
When or if regulatory action is taken, the States should be notified.

<table>
<thead>
<tr>
<th>RESPONSE</th>
<th>Noted.</th>
</tr>
</thead>
</table>

Shantha Varahan  
OCC  
Participation of the regulatory bodies in the development process is recommended.

<table>
<thead>
<tr>
<th>RESPONSE</th>
<th>Noted.</th>
</tr>
</thead>
</table>

Brenda Blundell  
OGE  
Rather than simply filing an Application at FERC seeking to have the combined organization be approved and recognized as meeting all of the requirements of Order 2000 for an RTO, the Term Sheet proposes submitting a joint Petition for Declaratory Order seeking a finding that the combination would satisfy the Order 2000 requirements for recognition as an RTO. OG&E believes the Application approach would move the proposed organizational structure more quickly along the path toward FERC recognition without incurring the filing fees associated with a Declaratory Order filing.

<table>
<thead>
<tr>
<th>RESPONSE</th>
<th>Noted.</th>
</tr>
</thead>
</table>

Kim Casey  
Dynegy  
Even though a declaratory order request will require a filing fee of $14,000, this seems like a good process to utilize in order to get an initial call from FERC on these important preliminary issues without incurring the time and expense of proceeding with a complete RTO filing and obtaining all the commitments that would entail.

<table>
<thead>
<tr>
<th>RESPONSE</th>
<th>Noted.</th>
</tr>
</thead>
</table>
12. FOR PROFIT CONVERSION
Both the MISO and SPP agree that if the Newco Board determines that Newco should become a for profit entity, then Newco may become such an entity.

<table>
<thead>
<tr>
<th>Name</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dave Christiano</td>
<td>Why?</td>
</tr>
<tr>
<td>CUS</td>
<td></td>
</tr>
<tr>
<td>Dick Dixon</td>
<td>It is unclear why a statement about Newco becoming a for profit entity is included. This statement should be eliminated and reserved for Board action at some future date if it is appropriate at that time.</td>
</tr>
<tr>
<td>WRI</td>
<td></td>
</tr>
<tr>
<td>Mike Deihl</td>
<td>Do not think this section is necessary. This is a decision that could be made at any time by the BOD.</td>
</tr>
<tr>
<td>SWPA</td>
<td></td>
</tr>
<tr>
<td>Shantha Varahan</td>
<td>Should the Newco have the ability to convert to a for-profit entity? Should this be limited in the bylaws? What types of events would trigger this action?</td>
</tr>
<tr>
<td>OCC</td>
<td></td>
</tr>
<tr>
<td>Frederick</td>
<td>Finally, the Term Sheet should make no reference to converting Newco to a for-profit entity. The East Texas Cooperatives, like other members of the SPP and MISO, have devoted substantial effort to developing a non-profit RTO. The non-profit model has certain important advantages over a model that has transmission revenues as its primary incentive. Therefore, the SPP should not assume that Newco would become a for-profit entity. The Newco Board may well decide to pursue such a conversion, but an eventual for-profit transmission operator should not be built into the Term Sheet.</td>
</tr>
<tr>
<td>Ochsenhirt ETxC</td>
<td></td>
</tr>
<tr>
<td>J. M. Shafer</td>
<td>Changing to a profit organization would need some definition for RUS, and possibly for our members?</td>
</tr>
<tr>
<td>WFEC</td>
<td></td>
</tr>
<tr>
<td>Brenda Blundell</td>
<td>As stated above, OG&amp;E believes that the decision to change the NEWCO to a for-profit corporation should be made by the membership, not the Board of NEWCO. This provision should be captured in the Articles of Incorporation for NEWCO rather than in the By-Laws unless changes to the By-Laws are restricted to membership vote. OG&amp;E does not favor a limitation to changes of the By-Laws to votes of the membership at large.</td>
</tr>
<tr>
<td>OGE</td>
<td></td>
</tr>
<tr>
<td><strong>RESPONSE</strong></td>
<td>This was included to allow future options.</td>
</tr>
</tbody>
</table>

13. INCENTIVES
The MISO and SPP agree that incentives must be developed for employees and officers of Newco based on reliability, cost control and general performance.

<table>
<thead>
<tr>
<th>Name</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kim Casey</td>
<td>Insert “efficiency, “ before “reliability”.</td>
</tr>
<tr>
<td>Dynegy</td>
<td></td>
</tr>
<tr>
<td><strong>RESPONSE</strong></td>
<td>Noted.</td>
</tr>
</tbody>
</table>
14. CONDITIONS REQUIRED TO BE SATISFIED
In order for any transaction to occur, the following conditions must be satisfied:

• The current Boards of Directors of both the MISO and SPP must approve a term sheet setting forth all material provisions for such a transaction and bearing the designation “Final Draft – Subject To Board Approval” on or before September 1, 2001;
• Appropriate definitive documentation agreed to by _____, 2001; and
• FERC approval is obtained.

15. MISCELLANEOUS
Definitive documents for the individual transactions necessary to accomplish the combination will include provisions typical for transactions of this type including but not limited to the following:

• Representations and warranties as to
  o organization and good standing, ability to enter into the transaction, etc.;
  o financial matters;
  o tax matters;
  o litigation, pending claims and compliance with laws;
  o contracts and commitments;
  o real property and other assets;
  o patents, trademarks, licenses and other intangibles;
  o insurance;
  o environmental matters, and
  o ERISA and employee benefit/HR matters;
• Indemnifications;
• Continuing conduct of business;
• Mutual cooperation and assurance;
• Regulatory approvals; and
• Choice of law

Time is of the essence for the matters discussed in this term sheet. Should we be in agreement to pursue a business combination between our organizations, due diligence would have to be scheduled and completed promptly and conformance of the proposal with both the MISO’s and SPP’s third party contractual obligations would have to be assured. Definitive documents would have to be created, executed and filed with the appropriate regulatory agencies by September 30, 2001.
This “Draft Term Sheet” is not an offer. It is intended to provide a basis for discussion among the parties. By executing the “Draft Term Sheet” in the spaces provided below, the Parties are committing only to continued discussions. Execution of the “Draft Term Sheet does not represent an obligation upon the parties to enter into a combination or other business transaction.

The laws of the State of Indiana, other than as to choice of law, shall control the construction and enforcement of this “Draft Term Sheet.”

| Brenda Blundell OGE | While the list contained in this paragraph is not limited, the list clearly does not recognize all of the definitive documents that must be finalized in order to accomplish the transaction. Rather than providing an incomplete list of definitive documents, OG&E proposes that this paragraph be rewritten as follows:
| | Definitive documents for the individual transactions necessary to accomplish the combination will include provisions typical for transactions of this type.
| RESPONSE | Noted. |

| Brenda Blundell OGE | This section also makes reference to the use of Indiana law as the controlling law for NEWCO. OG&E believes that NEWCO should be subject to the laws of the United States of America except (i) where real property is involved and the law of the state of the site would control, and (ii) commercial transactions should be subject to the laws of the State of New York, and in particular, the New York Uniform Commercial Code. |
| Kim Casey Dynegy | This does not make sense. Does Indiana law control or not? If so, why was Indiana law chosen? Are you trying to limit application of Indiana law just to the term sheet but preserving the ability to choose which state’s law will apply to the final merger documents? SPP will need to secure counsel licensed in Indiana to review whatever agreements are controlled by Indiana law. Are we prepared to do that? |
| RESPONSE | Noted. |
## MISO - SPP COMBINED BALANCE SHEETS (eff. 12/31/01)

<table>
<thead>
<tr>
<th></th>
<th>MISO 31-Jul-01</th>
<th>MAPP Acquisition</th>
<th>SPP 31-Jul-01</th>
<th>Combined 31-Jul-01</th>
<th>SPP Adjustments</th>
<th>MISO Adjustments</th>
<th>Final</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash and Cash Equivalents</td>
<td>75,543,749</td>
<td>(7,401,431)</td>
<td>16,056,708</td>
<td>84,199,026</td>
<td>(3,500,000)</td>
<td>(50,392,980)</td>
<td>30,306,046</td>
</tr>
<tr>
<td>Accounts Receivable</td>
<td></td>
<td></td>
<td>10,302,379</td>
<td>10,302,379</td>
<td></td>
<td></td>
<td>10,302,379</td>
</tr>
<tr>
<td>Accounts Receivable - Employees</td>
<td>441,805</td>
<td></td>
<td></td>
<td>441,805</td>
<td></td>
<td></td>
<td>441,805</td>
</tr>
<tr>
<td>Prepayments</td>
<td>3,003,101</td>
<td></td>
<td>225,131</td>
<td>3,228,232</td>
<td></td>
<td></td>
<td>3,228,232</td>
</tr>
<tr>
<td><strong>Total Current Assets</strong></td>
<td>78,988,655</td>
<td>(7,401,431)</td>
<td>26,584,218</td>
<td>98,171,442</td>
<td></td>
<td></td>
<td>43,836,657</td>
</tr>
<tr>
<td>Property and Equipment</td>
<td>22,995,484</td>
<td>19,640,508</td>
<td>10,134,720</td>
<td>52,770,712</td>
<td></td>
<td></td>
<td>52,770,712</td>
</tr>
<tr>
<td>Accumulated Depreciation</td>
<td>(758,959)</td>
<td>(11,157,314)</td>
<td>(5,979,747)</td>
<td>(17,896,020)</td>
<td></td>
<td></td>
<td>(17,896,020)</td>
</tr>
<tr>
<td>Construction in Progress</td>
<td>22,236,525</td>
<td>8,483,194</td>
<td>4,154,973</td>
<td>34,874,692</td>
<td></td>
<td></td>
<td>34,874,692</td>
</tr>
<tr>
<td><strong>Total Fixed Assets</strong></td>
<td>58,528,390</td>
<td>9,183,194</td>
<td>16,502,991</td>
<td>84,214,575</td>
<td>3,500,000</td>
<td>33,796,611</td>
<td>121,511,186</td>
</tr>
<tr>
<td>Other Assets</td>
<td></td>
<td></td>
<td></td>
<td>670,938</td>
<td></td>
<td></td>
<td>670,938</td>
</tr>
<tr>
<td>Deferred Bond Offering Fee</td>
<td>609,376</td>
<td></td>
<td></td>
<td>609,376</td>
<td></td>
<td></td>
<td>609,376</td>
</tr>
<tr>
<td>Deferred Regulatory Asset</td>
<td>42,858,349</td>
<td></td>
<td></td>
<td>42,858,349</td>
<td>13,516,751</td>
<td>15,930,051</td>
<td>72,305,151</td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>180,984,770</td>
<td>2,452,701</td>
<td>43,087,209</td>
<td>226,524,680</td>
<td>13,516,751</td>
<td>15,930,051</td>
<td>238,933,308</td>
</tr>
<tr>
<td>ST Debt</td>
<td>347,127</td>
<td></td>
<td></td>
<td>510,444</td>
<td></td>
<td></td>
<td>510,444</td>
</tr>
<tr>
<td>Accounts Payable</td>
<td>256,297</td>
<td>1,075,000</td>
<td>10,052,226</td>
<td>11,383,523</td>
<td></td>
<td></td>
<td>11,383,523</td>
</tr>
<tr>
<td>Accrued Liabilities</td>
<td>3,928,744</td>
<td>1,084,701</td>
<td>467,774</td>
<td>5,481,219</td>
<td>(666,318)</td>
<td>4,814,901</td>
<td>4,814,901</td>
</tr>
<tr>
<td>Accrued Interest</td>
<td>1,458,338</td>
<td></td>
<td>868,193</td>
<td>2,326,531</td>
<td></td>
<td></td>
<td>2,326,531</td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>5,214,338</td>
<td></td>
<td>5,214,338</td>
<td>5,214,338</td>
<td></td>
<td></td>
<td>5,214,338</td>
</tr>
<tr>
<td>Member Overpayments</td>
<td></td>
<td></td>
<td></td>
<td>0</td>
<td>13,516,751</td>
<td></td>
<td>13,516,751</td>
</tr>
<tr>
<td><strong>Total Current Liabilities</strong></td>
<td>5,990,506</td>
<td>2,159,701</td>
<td>16,765,848</td>
<td>24,916,055</td>
<td>13,516,751</td>
<td></td>
<td>37,766,488</td>
</tr>
<tr>
<td>Capital Leases</td>
<td>15,423,078</td>
<td></td>
<td></td>
<td>15,423,078</td>
<td></td>
<td></td>
<td>15,423,078</td>
</tr>
<tr>
<td>LTD</td>
<td>99,571,186</td>
<td>25,000,000</td>
<td>124,571,186</td>
<td>124,571,186</td>
<td></td>
<td></td>
<td>124,571,186</td>
</tr>
<tr>
<td>Deferred Revenues</td>
<td>60,000,000</td>
<td>293,000</td>
<td>60,293,000</td>
<td>60,293,000</td>
<td></td>
<td></td>
<td>60,293,000</td>
</tr>
<tr>
<td><strong>Total Liabilities</strong></td>
<td>180,984,770</td>
<td>2,452,701</td>
<td>41,765,848</td>
<td>225,203,319</td>
<td></td>
<td></td>
<td>238,053,752</td>
</tr>
<tr>
<td>Retained Earnings</td>
<td>1,321,361</td>
<td>1,321,361</td>
<td></td>
<td>1,321,361</td>
<td>(441,805)</td>
<td></td>
<td>879,556</td>
</tr>
<tr>
<td><strong>Total Liabilities and Equity</strong></td>
<td>180,984,770</td>
<td>2,452,701</td>
<td>43,087,209</td>
<td>226,524,680</td>
<td>13,516,751</td>
<td></td>
<td>238,933,308</td>
</tr>
</tbody>
</table>
### NEWCO

**SPP and MISO 2002 Budgets (1st drafts, not yet approved)**

<table>
<thead>
<tr>
<th>Item</th>
<th>MISO w/ MAPP</th>
<th>SPP</th>
<th>Combined</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Salaries &amp; Wages</td>
<td>$15,898,972</td>
<td>$8,067,906</td>
<td>$23,966,878</td>
</tr>
<tr>
<td>2 Employee Benefits</td>
<td>$7,666,604</td>
<td>$3,303,522</td>
<td>$10,970,126</td>
</tr>
<tr>
<td>3 Training/Relocation/Retention</td>
<td>$461,339</td>
<td>$453,000</td>
<td>$914,339</td>
</tr>
<tr>
<td>4 Office Expense</td>
<td>$502,513</td>
<td>$196,960</td>
<td>$699,473</td>
</tr>
<tr>
<td>5 Communications</td>
<td>$6,445,416</td>
<td>$1,360,730</td>
<td>$7,806,146</td>
</tr>
<tr>
<td>6 Travel, Meals, Entertain</td>
<td>$1,491,846</td>
<td>$979,485</td>
<td>$2,471,331</td>
</tr>
<tr>
<td>7 Directors Fees</td>
<td>$300,000</td>
<td>$248,000</td>
<td>$548,000</td>
</tr>
<tr>
<td>8 Contracting</td>
<td>$150,000</td>
<td>-</td>
<td>$150,000</td>
</tr>
<tr>
<td>9 Corporate Memberships</td>
<td>$31,168</td>
<td>$1,300,000</td>
<td>$1,331,168</td>
</tr>
<tr>
<td>10 Consultants/Outside Services</td>
<td>$5,370,739</td>
<td>$8,651,100</td>
<td>$14,021,839</td>
</tr>
<tr>
<td>11 Computer Maintenance</td>
<td>$765,331</td>
<td>$1,681,700</td>
<td>$2,447,031</td>
</tr>
<tr>
<td>12 Services, Utilities, Maintenance</td>
<td>$2,444,952</td>
<td>$60,000</td>
<td>$2,504,952</td>
</tr>
<tr>
<td>13 Cust Service/Sales/Misc.</td>
<td>$326,870</td>
<td>-</td>
<td>$326,870</td>
</tr>
<tr>
<td>14 Operating Leases</td>
<td>$2,169,888</td>
<td>$515,500</td>
<td>$2,685,388</td>
</tr>
<tr>
<td>15 Insurance</td>
<td>$3,518,105</td>
<td>$468,440</td>
<td>$3,986,545</td>
</tr>
<tr>
<td>16 Bank Charges</td>
<td>$120,504</td>
<td>$11,000</td>
<td>$131,504</td>
</tr>
<tr>
<td>17 Misc. Income</td>
<td>$(6,211,908)</td>
<td>$(2,368,700)</td>
<td>$(8,580,608)</td>
</tr>
<tr>
<td><strong>18 Severance Costs</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Operating Expenses</strong></td>
<td>$41,472,339</td>
<td>$24,928,643</td>
<td>$66,400,982</td>
</tr>
</tbody>
</table>

**Fixed Costs:**

interest (Long-Term Debt) $10,851,284 $1,875,000 $12,726,284

Depreciation - Capitalized Assets $16,416,513 $6,211,466 $22,627,979

**Total Other Expenses** $27,267,797 $8,086,466 $35,354,263

**Total Annualized Expenses** $68,740,136 $33,015,109 $101,755,245

GWH Load Served $557,607 $260,257 $817,864

Unbundled GWh Load 127,929 -

Bundled GWh Load $429,678 $260,257 $689,935

Unbundled Revenue 8,955,030.00 - 8,955,030.00

Costs Reduction - Unbundling $ (2,707,882) - $(2,707,882)

Revenue per MWh $0.123 $0.127 $0.124

Net Bundled Revenue $57,077,224 $33,015,109 $90,092,333

Revenue per MWh 0.133 0.127 0.131

Synergies from combination $7,902,953

Combined Annualized Costs post-combination $82,189,381

Revenue per MWh post-combination $0.119
Background
The implementation of NERC Compliance Templates P4-T2 and P4-T3 has required a review of SPP Criteria 5 for compliance with the templates and NERC Policy 4.

Analysis
The Operations Data Working Group carefully reviewed the applicable sections of SPP Criteria 5. Consideration was given to comments of the SWG raised in earlier meetings, the current and projected needs of the SPP Security Coordinators, and the ICCP implementation recommendations and practices of the NERC Data Exchange Working Group.

Recommendation
The attached documents reflect the recommended changes to SPP Criteria 5. Section 5.1 of SPP Criteria 5 has been significantly changed and now references Appendix 7 for details on what is to be exchanged and how. The original SPP Criteria 5 specified that the data would be exchanged at least every ten minutes. Appendix 7 specifies that the periodic ICCP data be exchanged no less frequently than every thirty seconds. This is consistent with the requirement to exchange periodic data on a thirty-second interval on the NERC ISN network as specified by the NERC Data Exchange Working Group. This recommendation would require Control Areas and other data suppliers to update their ICCP nodes from their host EMS at least every thirty seconds and to configure their ICCP nodes to allow the analog data to be sent to SPP at least every thirty seconds. Status point data will continue to be exchanged on a by-exception basis whenever possible, with a ten-minute integrity (periodic full dataset) report.

Approved
ODWG approved the recommendation August 2000
SWG approved the recommendation September 2000
EOC approved the recommendation September 2000

Action Requested
The EOC requests the Board of Directors approve the recommended changes to SPP Criteria 5.
5.0 SECURITY COORDINATION CENTER

Continuous coordinated operation of the bulk electric system is essential to maintain reliable electric service to all customers. Security coordination procedures are established herein for sharing of operating information and around-the-clock coordination of normal and emergency operating conditions to secure the reliability of the bulk electric system.

5.1 Information Exchange

Control areas shall share operating data regarding transmission facilities, generation facilities, system loads, interchange, area control error, frequency, and operating reserves as defined in Appendix 7 to the SPP Criteria and approved by the SWG. Non-Control Areas shall share operating data deemed necessary for assessment of regional security. Generator data for all generating units whose size is greater than or equal to the smaller of 10 MW or 5% of the reporting Control Area peak load and transmission circuit data for all interconnections, transmission facilities operated at 60kV or greater shall be automatically shared. This data shall be made available to the Security Coordinator and any other entity with immediate responsibility for interconnection security. The Security Coordinator shall obtain a signed code of conduct from entities receiving such data ensuring that the data will not be used for marketing purposes. Necessary operational data shall be made available on an interregional telecommunications network to support the requirements in this Criteria. This near real-time data will be exchanged at least every ten minutes or as otherwise requested by SPPs as specified in Appendix 7 and approved by the SWG.

5.1.1 Generation

Generator data for all generating units whose size is greater than or equal to the smaller of 10 MW or 5% of the reporting Control Area peak load shall be automatically shared. This includes but is not limited to generator unit status, MW and MVAR output, and MW rating, MW limitations, ready and spinning reserve, and voltage on the high side of the step-up transformer. For near term planning, each Control Area will share with the Security Coordination Center estimated return to service dates of existing generator outages, estimated outage dates and return to service dates of all future planned generator outages and generator dispatch plans for the current day and the next 6 days, all in a format specified by SPP and approved by SWG.
5.1.2 Transmission

Transmission circuit data for all interconnections, transmission facilities operated at 115 KV or greater and other transmission facilities considered key by the reporting Control Area shall be automatically shared. The following information shall be made available: element status, MW loadings, MVA ratings (static or dynamic), MVAR loadings and voltages. Pertinent transformer information shall also be shared. For near-term planning, each Control Area will also share with the Security Coordination Center estimated return-to-service dates of existing transmission equipment outages and estimated outage dates and return-to-service dates of all future planned transmission equipment outages, both in a format specified by SPP and approved by SWG.

5.1.3 Interchange

Each control area shall automatically share instantaneous actual and scheduled interchange and transmission service by individual control areas and by individual scheduled transactions, including degree of firmness. Each non-control area shall provide scheduled interchange and transmission service to the control area responsible for implementing the schedule. The security coordinator shall monitor schedules to assess overall network condition.

5.1.4 Performance Data

Each control area shall automatically share instantaneous non-adjusted area control error, clock-hour area control error, and system frequency.

5.1.5 Load Data

Hourly, each control area shall automatically share hourly integrated loads and inadvertent. For near-term planning, each control area will also share with the Security Coordination Center actual hourly loads for yesterday and forecasted hourly loads for the current day and the next 6 days (if available) in a format specified by SPP.
Data Dictionary for Electric System Security Data

Introduction

The data and terms described here are intended as a definition and clarification of the electric system security data required by SPP Criteria 5. The definitions herein were derived from the requirements listed in Appendix 4B of NERC Policy 4, Section B, System Coordination – Operational Security Information and the additional data required by Southwest Power Pool. Each term is defined and its current or expected method of exchange is specified.

Assumptions and Standard Conventions

1. All presently telemetered values must be supplied as specified in this appendix. Requests for real-time data not presently telemetered must follow the NERC data request process.
2. Control Areas that cannot provide some subset of the data required by this appendix may seek a waiver from the Security Working group (SWG).
3. It is assumed that Ampere measurements are used only for thermal limits calculations, and therefore, only an absolute value is required.
4. In some cases, MVAR Gross Output is measured rather than MVAR Net Output. Either value is usable provided the actual data type is known by the receiver and, in the case of Gross Output the necessary additional data is supplied to allow the Net Output to be calculated.
5. With respect to sign convention, positive is expected to be out of the bus and out of the generating unit at the point of measurement. The ISN Data Definition File, UsageMultiplier value must be defined as a negative value (normally -1.0) if the measurement does not follow this convention.
6. The ICCP standard does not discuss the scaling of analog quantities. Conversion to correct units is the responsibility of the originating host. Where that is not possible, the UsageAdder and UsageMultiplier values on the ISN Data Definition File must define the appropriate scaling factors. Sign (direction) conversion is the responsibility of the receiver.
7. ICCP data will be exchanged via the following blocks:
   1. BLOCK 1: Periodic dataset at the defined periodicity
   2. BLOCK 2: Exception triggered dataset, Report by Exception, 5 second buffering period, 10 minute integrity (full dataset) transmission.
8. The acceptable values assigned to the indication status point are prescribed in IEC 870-6-802 TASE.2 Object Models, Section 8.1 Use of IndicationPoint Models. Specifically, the following values are expected:
   0 Between
   1 Tripped, Open, Off, Out-of-service
   2 Closed, On, In-service

   If the sender of the data cannot accommodate the above standard, documentation of the possible values and their meaning must be provided to SPP.
9. All measurements to be exchanged via ICCP will be defined in the NERC ISN Data Definition File.
10. Gross or net generation measurements can be accepted. If gross measurements are supplied, the station auxiliary measurements must also be supplied so that net measurements can be derived.

Data Prescribed by NERC Appendix 4B

Transmission Data

Status
Description
Status of the switching devices (breakers, switches, disconnects) at each end of a transmission line. Possible values are Open and Closed for two-state devices and Open, Closed, and Between for three state devices.

Exchange Mechanism
ICCP Block 2.

Transmission Facility Loading (MW or Ampere Loadings)
Description
Instantaneous power flow (MW and MVar) or instantaneous current flow (ampere loading) on the transmission facility. If ampere loading is provided, voltage measurement on the same facility must also be provided.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

MVA Capability
Description
MVA limit for transmission facilities. This may be either a static or dynamic limit.

Exchange Mechanism
Dynamic limits: ICCP Block 1, 30 second maximum periodicity.
Static limits: Network model exchange or other mechanism to be defined.

Transformer Tap Setting
Description
Predefined, fixed positions on one or both sides of a transformer. Each Tap position represents a specific voltage value. (i.e. changing a Tap Position changes the voltage.) There is no standard numbering scheme for the tap position. For example, some utilities number beginning at 0, others at 1. Other utilities refer to the nominal position as position 0, with positive integers for positions above nominal, and negative integers for positions below nominal. Still other utilities use turns ratio and not position notations. Documentation defining the possible values and their meaning must be provided to SPP, either as part of the exchanged network model or as a separate document.
Exchange Mechanism
Telemetered or derived tap positions: ICCP Block 1, 30 second maximum periodicity.
Non-telemetered and no-load tap information: Network model exchange or other mechanism to be defined.

Transformer Phase Angle Setting
Description
Represents the Phase Angle between the current and voltage. (i.e. changing the Phase Angle changes the power.) The angle settings can typically vary between -90 and +90. The unit of measurement is Degrees.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Key Voltage
Description
Instantaneous voltage measurement for all telemetered locations on the transmission network. Unit of measurement is kV. PerUnit, 100Base, 120Base, etc. voltages must be converted to simple kV readings by the originator or, if not possible, the appropriate scaling factors must be defined.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Generator Data

Status
Description
Status of the generator as telemetered, or as derived from the status of the breaker associated with the generator unit. Possible values are In-service, Out-of-service and Between, or On, Off and Between.

Exchange Mechanism
ICCP Block 2

MW Capability
Description
Limit on the gross or net MW output of a generator unit. This value may be either a static or dynamic limit.

Exchange Mechanism
Dynamic limits: ICCP Block 1, 30 second maximum periodicity.
Static limits: Network model exchange or other mechanism to be defined.
MVAR Capability
Description
MVAR Capability Curve for a generating unit.

Exchange Mechanism
Network model exchange or other mechanism to be defined.

MW Output
Description
Instantaneous measurement of the gross or net real output power from the generator.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

MVAR Output
Description
Instantaneous measurement of the gross or net imaginary output power from the generator.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Status of Automatic Voltage Control Facilities
Description
Instantaneous telemetered or derived status of automatic voltage regulators, and if they exist, the statuses of fast acting exciters and stabilizers. Possible values are In-service, Out-of-service, and Between, or On, Off, and Between.

Exchange Mechanism
ICCP Block 2

Operating Reserve

MW Reserve Available Within Ten Minutes
Description
The amount of additional power that can be made available to the system within 10 minutes, as defined in SPP Criteria 6.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.
Control Area Demand

Instantaneous Control Area Demand
Description
Instantaneous calculation of the generation minus actual interchange for the control area. The unit of measurement is MW.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Interchange

Instantaneous Actual Interchange With Each Control Area
Description
Instantaneous reading of the MW flow between control areas.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Current Interchange Schedules With Each Control Area By Individual Interchange Transaction
Description
Current scheduled MW flows between control areas, and may include interchange identifiers and reserve responsibilities.

Exchange Mechanism
Electronic Tagging.

Interchange Schedules For the Next 24 Hours
Description
Interchange schedules with each control area by individual interchange transaction for the period encompassing the next hour to 24 hours into the future.

Exchange Mechanism
Electronic Tagging.

Area Control Error and Frequency

Instantaneous Area Control Error
Description
Instantaneous measurement of the area control error. Unit of measurement is MW. Value may be positive or negative.
Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Clock Hour Area Control Error
Description
Instantaneous Area Control Error averaged since the start of the current hour. This value may be positive or negative. Unit of measurement is MW.

Exchange Mechanism
This measurement is NOT required by SPP.

System Frequency At One or More Locations in the Control Area
Description
Instantaneous reading of the actual frequency in Hz. This is not the deviation from a value (nominally 60 Hz).

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Other Operating Information

Special Operating Security Limits in Effect
Description
Notification of special operating security limits in effect.

Exchange Mechanism
To be defined. Expected to be exchanged via Security Data Applications (SDA) or Web interface.

Forecast of Operating Reserve at Peak, and Time of Peak for Current Day and Next Day
Description
Estimate of the operating reserve at the time of peak demand. Unit of measurement is MW. The time is the local clock time, with time zone specified, for the peak demand.

Exchange Mechanism
Load and Capability Report (requires modification to include time of peak).

Forecast Peak Demand for Current Day and Next Day
Description
Estimate of the peak demand for the day. Unit of measurement is MW.
Exchange Mechanism
Load and Capability Report.

Forecast Changes in Equipment Status
Description
Notification of expected changes in availability of equipment, or special protection schemes, such as equipment being placed into service or taken out of service.

Exchange Mechanism
Generation and Transmission Outage Reports.

New Facilities in Place
Description
Notification of new equipment being placed into service.

Exchange Mechanism
To be determined.

New or Degraded Special Protection Systems
Description
Notification of changes to the status of special protection schemes and systems.

Exchange Mechanism
To be determined.

Emergency Operating Procedures in Effect
Description
Notification of Emergency conditions and procedures and expected duration. This may also include Transmission Loading Relief states, Energy Emergency Alerts, and relevant information such as action taken or planned.

Exchange Mechanism
IDC, ARS, and other mechanisms to be determined.

Severe Weather, Fire, or EarthQuake
Description
Notification of severe weather conditions such as hurricanes, tornadoes, and severe thunder storms. May also include tornado and severe weather warnings and watches, and solar magnetic disturbance alerts. Also includes notification of earthquakes, and fires that affect or could potentially affect the power system operation.

Exchange Mechanism
To be determined.
Multi-site Sabotage
Description
Notification of cases of sabotage to power system equipment at multiple sites.

Exchange Mechanism
NIPC/NERC IAW Reporting Procedures (InfraGard or SCIS).

Additional Data Required by SPP

Scheduled Base Frequency
Description
Instantaneous reading of the scheduled (base) frequency in Hz. This is not the deviation from a value (nominally 60 Hz). If this value is only valid during periods of time correction, then a status indication value must also be supplied to indicate whether time correction is in effect or not.

Exchange Mechanism
Scheduled Base Frequency: ICCP Block 1, 30 second maximum periodicity.
Time Correction status: Block 2.

Scheduled Net Interchange With Each Control Area
Description
Scheduled net MW flow between control areas.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Instantaneous Actual Total Net Interchange
Description
Instantaneous total net MW flow into or out of the Control Area.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Scheduled Total Net Interchange
Description
Total scheduled MW flow into or out of the Control Area.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.
CPS Report
Description
Monthly NERC reporting requirement for each Control Area. The report includes CPS1 and CPS2 data reporting.

Exchange Mechanism
SDA or Web Interface, reported to SPP no later than the 10th of the month for the previous month.

Inadvertent Accounting Report
Description
Monthly NERC reporting requirement for each Control Area.

Exchange Mechanism
SDA or Web Interface, reported to SPP no later than the 10th of the month for the previous month.

AIE Report
Description
NERC reporting requirement when an AIE report is requested for each Control Area.

Exchange Mechanism
SDA or Web Interface, submitted upon request.

Hourly Load Report
Description
Historical load reporting required from each Control Area for SPP reporting requirements. Hour by hour actual loads along with the average high temperature for the day and the deviation of the temperature from the normal high are required.

Exchange Mechanism
SDA or Web Interface. Reports may be made daily, weekly, or monthly, so long as the previous month has been completely reported by the 15th of the current month.

Unit Commitment Report
Description
Control Area generation plans for the current day and next six days. Data can be submitted either as a unit by unit hourly MW commitment or a block loading order with accompanying unit by unit hourly status.

Exchange Mechanism
SDA or Web Interface, submitted daily.
Load Forecast Report

Description
Hourly forecast / actual integrated load, in MW, for the prior, current, and next six days. Prior day actual loads are mandatory. Current and next six day forecast loads are requested. If the current and future day forecast is not supplied, a forecast will be derived from previously reported actual loads.

Exchange Mechanism
SDA or Web Interface, submitted daily.
Southwest Power Pool
ENGINEERING AND OPERATING COMMITTEE
Recommendation to the Board of Directors
October 17, 2001

TRANSMISSION MAINTENANCE REVIEW PROCEDURES

Background
The SPP RTO Membership Agreement requires planned maintenance of transmission and generation facilities to be coordinated with SPP. It further requires SPP to review maintenance schedules of those transmission facilities committed to the regional tariff consistent with SPP’s business practices. The Membership Agreement defines transmission facilities as those subject to SPP Operational Control that are 60 kV and above. The existing SPP Criteria 5 requires that scheduled outages of transmission facilities greater than 115 kV be coordinated with SPP.

Recent Activity
Draft generation and transmission maintenance review procedures to be used as SPP business practices were first submitted to the SWG at their April 24-25, 2000 meeting. The procedures were revised and reviewed at the June 1-2 and again at the August 23-24, 2000 meetings. At the August 23-24 meeting, the SWG asked that SPP Criteria 5 be revised to be more consistent with the Membership Agreement and to require SPP approval of transmission maintenance schedules. The maintenance review procedures and associated Criteria 5, Section 5.2 changes were submitted to the SWG for discussion on a September 1, 2000 conference call.

Analysis
The SWG reviewed the procedures and Criteria 5 changes to ensure that outage coordination on a regional basis would be facilitated to maximize regional reliability efforts. The SWG also compared the suggested Criteria 5 changes and maintenance review procedures with the requirements of the Membership Agreement to ensure consistency.

Conclusion
The SWG, concerned with security issues involving the current language in the Membership Agreement about generation maintenance outage coordination, agreed to approve the Transmission Maintenance Review Procedures and associated Criteria 5 changes but defer the Generation Maintenance Review Procedures until those issues could be addressed.

Recommendation
Engineering and Operating Committee is recommending that the attached Criteria 5, Section 5.2 changes be approved and the attached Transmission Maintenance Review Procedures be approved as acceptable SPP business practices.

Approved
Security Working Group September 2000
Engineering and Operating Committee September 2000

Action Requested: Approve SWG recommendation.
Maintenance Review and Approval Process for
Transmission Outages

Definitions

Critical Facilities - All Transmission Facilities in the SPP Region rated at 230 kV and above, tie-line facilities, facilities that affect the capability and reliability of generating facilities, and other facilities classified as having a major impact on the transmission system. For classifying transformers as Critical Facilities, the low-side voltage class will be used. See Attachment A for a list of Critical Facilities.

Security Coordinator - SPP in performing its security coordinator function as recognized by NERC pursuant to its policies, pursuant to SPP Criteria and pursuant to the SPP Membership Agreement.

SPP Criteria - SPP’s approved operating and planning criteria.

SPP Region - The geographic area encompassing the transmission systems of SPP Transmission Owners.

Tariff Facilities - The Transmission Facilities and Distribution Facilities subject to SPP’s tariff administration.

Transmission Customer - A customer under the Transmission Tariff.

Transmission Facilities – The facilities subject to SPP’s Operational Control as defined in the SPP Membership Agreement and any other facilities not transferred to SPP’s Operational Control but belonging to transmission owners under SPP’s purview as a Security Coordinator. These facilities consist of transmission facilities that are 60 kV and above and transformers with two primary windings of 60 kV and above. SPP may direct the transfer of other transmission facilities to its Operational Control subject to all necessary regulatory approvals being received.

Transmission Owner - A signatory to the SPP Membership Agreement which appoints SPP as its agent to provide service under the Transmission Tariff over Tariff Facilities which it owns or controls and any owner of Transmission Facilities under SPP’s purview as a Security Coordinator.

Transmission Outage Review

1. Maintenance review and approval will be done according to the submit time of the outage posting or update on the SPP Transmission Outage Application (TRAN).
2. Planned maintenance outages of all SPP Critical Facilities must receive explicit approval from SPP. Planned maintenance of all other Transmission Facilities shall be coordinated with SPP.
3. Only Tariff Facilities are eligible for deferred maintenance compensation. In order for a Tariff Facility to be eligible for deferred maintenance compensation, it must have been previously approved by SPP.
4. Outage requests on Critical Facilities will be coordinated such that minimal interruption of firm transmission service occurs. Maintenance outages that result in unacceptable degradation of reliability will not be approved.
5. Transmission maintenance schedules must be submitted for a minimum of a rolling one-year period updated on a daily basis. Changes and additions to the yearly maintenance schedule must be posted 7 or more days in advance of the start time of the outage and approved by SPP to be eligible for deferred maintenance compensation. The SPP Security Coordinator will approve or deny each Critical Facility outage request as soon as possible but no later than the times indicated in the following table.

<table>
<thead>
<tr>
<th>Outage Submission Time</th>
<th>SPP Response Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 year or greater</td>
<td>20 business days</td>
</tr>
</tbody>
</table>

5-2
<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1 month up to 1 year</td>
<td>10 business days</td>
</tr>
<tr>
<td>7 days up to 1 month</td>
<td>2 business days</td>
</tr>
</tbody>
</table>

6. Maintenance requests of Critical Facilities or changes in approved schedules that are posted less than 7 days in advance of the start time of the outage must be accompanied by a report at the time of submission explaining the reason for such late notification. If the late notice for a maintenance outage is necessary due to safety, reliability, or equipment damage on the facility, SPP will use expedited procedures to coordinate with the affected transmission operator to facilitate the outage. If this is not the case, SPP will accommodate the request if practicable. If it is not practicable to accommodate the late request, it will be denied.

7. Due to the nature of Nuclear Units and safety of the public, outages concerning major transmission facilities supplying the associated substation/switching station will receive special consideration in scheduling.
Security Coordinator Process

1. Perform a daily 7-day maintenance review, beginning with the next day, and other maintenance reviews beyond the 7-day horizon as those outages are posted.
2. Review the contingency analysis from Seven-Day Maintenance Review and other maintenance reviews as necessary.
3. If any limitations appear, notify an Operations Support Engineer or the Supervisor, Security Coordination.
4. If no limitation is apparent, skip to step 10.
5. If a limitation appears, contact the owner(s) of the facility and ask them to verify that this is not a local-area problem and should be considered a security risk. Also verify the projected generation dispatch pattern of the model with the control area(s) for reasonableness. Report any significant dispatch errors to the Operations Support Engineers. If the facility still appears to be a valid security risk, continue to step 6. If not, go to step 10.
6. Identify all unapproved outages in the area that may be contributing to the situation.
7. Review the impacts of each by putting the unapproved facilities back in service and re-solve the case with the contingency element producing the constraint open. Note the change in flow on the constrained facility compared to the post contingency flow from the “Maintenance Review Report” with all outages taken. If there is no significant change, contact an Operations Support Engineer. This may be a situation requiring deferred maintenance or the development of an Operating Guide.
8. If a significant change in flow can be seen such that putting all unapproved outages back in service relieves the constraint, take each unapproved outage individually to determine which is causing the most adverse impact.
9. Once the most limiting, unapproved outage(s) has (have) been identified, contact the Supervisor, Security Coordination for final review before denying the outage request.
10. Change the status of the outage(s) as appropriate using the Transmission Outage Application (TRAN).
5.2 Security Coordination

5.2.1 Member Responsibilities
Control areas shall notify the security coordinator of current or foreseen operating conditions that may adversely affect interconnection reliability. Scheduled transmission outages of critical transmission facilities shall be approved coordinated with the security coordinator. Scheduled outages of all other facilities greater than 60 kV shall be coordinated with the Security Coordinator. The Security Working Group shall be responsible for identifying those facilities classified as critical. Non-control areas shall notify their control area of current or foreseen operating conditions that may adversely affect interconnection reliability. Scheduled transmission outages shall be coordinated with their control area.

5.2.2 Security Working Group
The Security Working Group shall be responsible for policy oversight of implementation and ongoing security coordination processes and services as described in this Criteria. This working group shall make regular reports to the Engineering & Operating Committee.

5.2.3 SPP Staff
The SPP Staff shall be responsible for development and administration of security coordination processes and services as described in this Criteria, including budgeting and staffing requirements.

5.2.4 Security Coordinator Responsibilities
On a continuous around-the-clock basis, the SPP Security Coordinator shall be responsible for the following activities:

5.2.4.1 Daily Reliability Assessment
a. Monitor the collection of operating information from control areas on a ten minute cycle, including; load, area interchange error, scheduled transactions, interconnection real and reactive power flows, status of all transmission facilities at 115 kV and above plus selected 69 kV facilities, and generator real and reactive output, ready and spinning operating reserve, minimum and maximum unit output constraints, and voltage.
b. Develop and use an operational model to assess security and adequacy of the electric system, including; ability to handle more probable contingencies and remain within operating criteria, anticipating line loading problems, and determining the adequacy of operating reserve.

c. During conditions where system reliability is threatened, notify and work with control areas in determining appropriate control action.

5.2.4.2 Daily Operational Coordination

a. Monitor, coordinate and grant permission for bulk transmission equipment maintenance.
b. Manage the SPP Open Access Same-Time Information System node and ATC calculation.
c. Monitor the NERC Hot line and disseminating information.
d. Initiating time error corrections.

5.2.4.3 Compliance Monitoring

a. Assess and report regional compliance with NERC operating criteria, including; area interchange error, CPS1, CPS2, DCS, frequency response, and inadvertent.
b. Coordinate bilateral inadvertent energy accounting and payback.

5.2.4.4 Emergency Procedure Implementation

a. Monitor and coordinate implementation of Operating Reserve Criteria.
b. Monitor and coordinate implementation of Line Loading Relief Criteria.
c. Monitor and coordinate implementation of Load Shedding and Restoration Criteria.
d. Monitor and coordinate implementation of Black Start Criteria.
e. Issue short supply advisories.
f. Issue weather advisories.

5.2.4.5 Interregional Coordination

a. Coordinate normal and emergency operations with other Security Coordinators.
b. Authoritatively act on behalf of SPP Members to resolve interregional issues.

5.2.5 Security Coordinator Authorities

The SPP Security Coordinator shall have authority over the following activities:
a. Confirm transactions during periods of Line Loading Relief as outlined in Criteria.
b. Direct implementation of Black Start procedures as outlined in Criteria.
c. Implement Line Loading Relief Procedures as required.

5.2.6 Security Coordinator Performance Standards

The SPP Security Coordinator shall have the following performance standards:

a. The SPP Security Coordinator shall act in accordance with Good Utility Practice including NERC Policies and SPP Criteria, shall not order SPP members to take any action that would not be in accordance with Good Utility Practice, and shall allow SPP members to take any actions required by Good Utility Practice.

b. The SPP Security Coordinator shall not take any action, or direct SPP members to take any action, which would be in violation of any lawful regulation or requirement of any governmental agency.

c. The SPP Security Coordinator shall carry out its responsibilities in at least as prompt and efficient a manner as that required by Good Utility Practice including NERC Policies and SPP Criteria.

d. The SPP Security Coordinator shall monitor adherence to its directives and report non-compliance to the appropriate SPP organizational group.

e. The SPP Security Coordinator shall be a certified system operator as defined by related SPP Criteria.

f. The SPP Security Coordinator shall sign an appropriate standards of conduct document ensuring appropriate protection of competitively sensitive information.
Southwest Power Pool
ENGINEERING AND OPERATING COMMITTEE
Recommendation to the Board of Directors
October 17, 2001

DISTURBANCE MONITORING EQUIPMENT (DME) CRITERIA 7.1
TRANSMISSION PROTECTION SYSTEMS (TPS) CRITERIA 7.2
SPECIAL PROTECTION SYSTEMS (SPS) CRITERIA 7.4
UNDERVOLTAGE LOAD SHEDDING (UVLS) CRITERIA 7.5
AUTOMATIC RESTORATION OF LOAD (ARL) CRITERIA 7.6
GENERATION CONTROL AND PROTECTION (GCP) CRITERIA 7.7
PROTECTIVE RELAYING, MONITORING AND CONTROLS (PRMC) CRITERIA 3.5

Background
The NERC Compliance Program was developed to ensure compliance with the NERC Planning Standards and Operating Policies and Standards. This Program includes Standards to ensure that the reliability of the interconnected bulk electric systems is maintained in the more competitive electricity markets. These Standards define what the reliability requirements are to those who plan, operate and use the systems. SPP, as a region of NERC, is responsible to comply with these Standards.

PRMC 3.5: During the development of SPP’s new Regional Transmission Planning Criteria 3, the previous Protective Relaying Criteria 3.4 addressing general planning requirements was not included.

Recent Activity
All Criterion Except UFLS 7.3 & PRMC 3.5: The System Protection and Control Working Group (SPCWG) addressed the Standards that are required in the year 2001 and are the responsibility of the SPCWG. These Standards were reviewed given the most current applicable templates from NERC to ensure that SPP complies with all Measurements defined in each of these Standards. The SPCWG reviewed the report of the SPP NERC Planning Standards Task Force which was released February 3, 1998. Based on the recommendations of this report and the current Standards, the SPCWG identified no existing SPP criteria as applicable to the Standards.

PRMC 3.5: The System Protection and Control Working Group (SPCWG) addressed this issue and determined that references to protection and control requirements should be included in the Regional Transmission Planning Criteria 3. The reasoning for this is with references to protection, monitoring and control requirements as specified in Criteria 7, those involved specifically in planning processes will be advised of these requirements and directed to the appropriate criteria. Without such references, significant requirements of facility owners during the planning processes may not be addressed.
**Analysis**

The SPCWG developed the new Criterion 7, excluding UFLS 7.3, based on the recommendations by the SPP NERC Planning Standards Task Force. The new criterion was developed to include the requirements of each current Measurement in the applicable Standards as required by NERC.

**DME 7.1:** The requirements of measures M1 through M4 of NERC’s Template I.F were included in this criteria.

**TPS 7.2:** The requirements of measures M1 through M4 of NERC’s Template III.A were included in this criteria.

**SPS 7.4:** The requirements of measures M1 through M6 of NERC’s Template III.F were included in this criteria.

**UVLS 7.5:** The requirements of measures M1 through M5 of NERC’s Template III.E were included in this criteria.

**ARL 7.6:** The requirements of measures M1 through M4 of NERC’s Template IV.B were included in this criteria.

**GCP 7.7:** The requirements of measures M10 through M12 of NERC’s Template III.C were included in this criteria.

**PRMC 3.5:** The SPCWG developed the new Criteria 3.5, Protective Relaying, Monitoring And Controls, based on the previous Criteria 3.4. The new criteria was developed to reference the requirements of Criteria 7.1 through 7.7.

**Conclusion**

**All Criterion Except UFLS 7.3 & PRMC 3.5:** Additional requirements of NERC have been incorporated into the new criteria such that SPP and its members maintain an acceptable level of compliance in accordance with NERC’s current Standards and Measures. NERC requires that each region develop programs to include Disturbance Monitoring Equipment, Transmission Protection Systems, Special Protection Systems, Undervoltage Load Shedding, Automatic Restoration of Load, and Generation Control and Protection. These programs shall coordinate within the sub-regions and Region.

**PRMC 3.5:** The previous planning requirements specified in Criteria 3.4 were updated to include references to NERC’s new requirements as addressed in Criteria 7.1 through 7.7. By including these references in Criteria 3.5, those involved in planning processes will be advised on the protection and control requirements that should be addressed during the planning of future modifications to the transmission system.

**Recommendation**

The EOC recommends the Board of Directors approve the new
Criterion 7.1, 7.2, 7.4, 7.5, 7.6, 7.7. The EOC recommends the Board of Directors direct the Transmission Assessment Working Group and the Security Working Group to review the equipment databases on an annual basis per 7.1.4, 7.4.4, 7.5.6 and 7.6.6. The SPCWG recommends that the Transmission Assessment Working Group and the Security Working Group provide recommendations of equipment capability and locations per 7.1.2, 7.4.2, 7.5.3 and 7.6.3.

**Approved**
Recommendations were approved at the SPCWG February 2001
Recommendations were approved the EOC March 2001

**Action Requested**
Approve the new Criterion 7.1, 7.2, 7.4, 7.5, 7.6, 7.7 and 3.5
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Protective Relaying, Monitoring & Controls – Criteria 3.5 37
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 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 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, the system protection equipment criteria 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, the Transmission Protection Systems criteria every three (3) years.
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 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 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 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, the SPS 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 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 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 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 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, the UVLS 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 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 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 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, the ARL 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 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 occurring 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 every three (3) years.
3.5 Protective Relaying, Monitoring And Controls

Protective relaying, communications and instrumentation play an important role in maintaining the reliability of the bulk electric system. Protective Relay Systems (PRS) requirements shall be taken into account during the planning and design of generation, transmission and substation configurations. If configurations are proposed that require PRS that do not conform to this criteria or to accepted IEEE/ANSI practice, then the entities affected shall negotiate a solution. The principles for planning additions in these categories are set forth in this Criteria.

a. The bulk power protective relay system design shall have as its objective rapid clearing of all faults, with no fault permitted to remain uncleared despite the failure of any single protective system component. To accomplish this, transmission protection systems shall be installed as specified in Transmission Protection Systems Criteria 7.2.

b. Control areas shall maintain communications systems to their generating stations, operation centers and to neighboring utilities which shall provide adequate communication in the event of failure of any one element of the systems. In general, such communication systems should not be susceptible to failure during an interruption of the A.C. power supply in any part or all of their areas.

c. Loadings on the bulk electric system shall be monitored continually to insure that operation is within safe limits.

d. Suitable instrumentation, and/or other devices, shall be installed to measure appropriate quantities at key points in the electric system with appropriate automatic alarms.

e. Fault recording devices as described in Criteria 7.1 shall be installed at appropriate points within the SPP region so that outages and short circuits can be analyzed and protective relay performance studied. In addition, Disturbance Monitoring Equipment shall be provided to meet Criteria 7.1 so that system disturbances may be analyzed.

f. Underfrequency Load Shedding equipment shall be installed pursuant to Criteria 7.3 for the purpose of maintaining a stable operating frequency.

g. As specified in Criteria 7.4, Special Protection Systems when installed shall detect abnormal system conditions and take pre-planned,
coordinated, corrective action to provide acceptable system performance.

h. When Undervoltage Load Shedding equipment is installed by a member system as specified in Criteria 7.5 for the purpose of stabilizing interconnected systems and mitigating the effects of voltage collapse, then this program shall coordinate with all other schemes of which include system protection, Underfrequency Load Shedding, Automatic Restoration of Load and Generation Control and Protection.

i. Given the requirements of Criteria 7.6, Automatic Restoration of Load schemes may be installed by member systems to expedite load restoration. These systems shall be coordinated with all other schemes such as system protection, Underfrequency Load Shedding, Undervoltage Load Shedding, and Generation Control and Protection. These systems shall operate only after underfrequency and/or undervoltage events.

j. Generation Control and Protection schemes shall be designed pursuant to Criteria 7.7 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 generator equipment from damage.
Background
The NERC Compliance Program was developed to ensure compliance with the NERC Planning Standards and Operating Policies and Standards. This Program includes Standards to ensure that the reliability of the interconnected bulk electric systems is maintained in the more competitive electricity markets. These Standards define what the reliability requirements are to those who plan, operate and use the systems. SPP, as a region of NERC, is responsible to comply with these Standards.

Recent Activity
The Generation Working Group (GWG) addressed the standards that are required in the 2001 compliance year and that were assigned to the GWG by the Compliance Dept. of the SPP Staff. The Standards were reviewed given the most current applicable templates from NERC to ensure that SPP complies through its criteria with all the Measurements defined in each of the Standards. The GWG identified that no existing SPP criteria as applicable to the Standards.

Analysis
The GWG developed the new Criteria 7.8, Generator Controls - Status and Operation, to comply with the NERC Planning Standards assigned to the group. The new criteria was developed to include the requirements of each current Measurement in the applicable Standards as required by NERC. The requirements of Measures M1 through M9 of NERC’s Template III.C were included in this criteria.

Conclusion
Additional requirements of NERC have been incorporated into new criteria such that SPP and its members maintain an acceptable level of compliance in accordance with NERC’s current Standards and Measures.

Recommendation
Engineering and Operating Committee recommends the Board of Directors approve the new Criteria 7.8 as attached.

Approved
Generation Working Group February, 2001
Engineering and Operating Committee March, 2001

Action Requested
Approve the new Criteria 7.8, Generator Controls – Status and Operation.
Criteria 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
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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 impedance 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 if 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.
Southwest Power Pool Criteria 7.8

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 Generator Owner/Operator
Excitation System Summary Report

Instructions: Generator Owner/Operator shall fill out summary information for all units under your control concerning the number of hours the Excitation System was not operated in Automatic Voltage Control Mode.

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<thead>
<tr>
<th>Generator Owner/Operator</th>
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<tbody>
<tr>
<td>Month Reporting Data</td>
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<tr>
<td>Contact Name</td>
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<td>Contact Phone</td>
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<table>
<thead>
<tr>
<th>Station</th>
<th>Unit #</th>
<th># Hours Excitation System not operated in Automatic Voltage Control Mode</th>
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Dev. February, 2001
By SPP GWG
## Southwest Power Pool
### Generator Unit Excitation System Status Report

Instructions: Generator Owner/Operator shall fill out information concerning the frequency and duration of events of a particular generating unit’s excitation system not being operated in automatic voltage control mode.

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<th>Generator Owner/Operator</th>
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<tr>
<th>Generating Unit</th>
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<thead>
<tr>
<th>Month Reporting Data</th>
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<tr>
<th>Contact Name</th>
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<th>Contact Phone</th>
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<table>
<thead>
<tr>
<th>Date (unit not operated in automatic mode)</th>
<th>Unit #</th>
<th>Reason unit’s excitation system was operated out of automated voltage control mode</th>
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Dev. February, 2001
By SPP GWG
Southwest Power Pool Generator Owner/Operator
Voltage Schedule Requirements

Instructions: Control Area Operator shall specify voltage schedule to be maintained by each Generator Owner/Operator’s units at a specified bus.

<table>
<thead>
<tr>
<th>Generator Owner/Operator</th>
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<tbody>
<tr>
<td>Control Area</td>
<td></td>
</tr>
<tr>
<td>Voltage Schedule Date</td>
<td></td>
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<tr>
<td>Contact Name</td>
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<tr>
<td>(Control Area)</td>
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<td>Contact Phone</td>
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<td>(Control Area)</td>
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<thead>
<tr>
<th>Station</th>
<th>Unit #</th>
<th>Specified Voltage</th>
<th>Specified Bus</th>
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Dev. February, 2001
By SPP GWG
Southwest Power Pool Generator Unit  
Voltage Schedule Status Report

Instructions: Generator Owner/Operator shall fill out information concerning the frequency and duration of periods in which particular generating units did not adhere to control area’s prescribed voltage schedule. If event was approved by control area operator, please attach written approvals.

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<thead>
<tr>
<th>Generator Owner/Operator</th>
<th>Generating Unit</th>
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<tbody>
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<table>
<thead>
<tr>
<th>Month Reporting Data</th>
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<tbody>
<tr>
<td>Contact Name</td>
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<td>Contact Phone</td>
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<table>
<thead>
<tr>
<th>Date</th>
<th>Duration (hr:min)</th>
<th>Reason unit did not adhere to voltage schedule</th>
<th>Approved (yes/no)</th>
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Dev. February, 2001
Southwest Power Pool
Control Area’s List of Exempt Generators

Instructions: Control Area Operator shall list units in their area of responsibility that are exempt from following prescribed Control Area Voltage Schedules.

<table>
<thead>
<tr>
<th>Control Area Operator</th>
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<tbody>
<tr>
<td>Last Updated</td>
<td></td>
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<tr>
<td>Contact Name</td>
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<td>Contact Phone</td>
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<table>
<thead>
<tr>
<th>Generator Owner/Operator</th>
<th>Generating Station</th>
<th>Unit</th>
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Dev. February, 2001
By SPP GWG
Southwest Power Pool
Generator Unit Transformer Tap Setting Report

Instructions: Generator Owner/Operators shall fill out information concerning the tap settings and impedances of all GSU and AUX transformers under their control.

<table>
<thead>
<tr>
<th>Generator Owner/Operator</th>
<th>Generating Station</th>
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<th>Contact Name</th>
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<th>Contact Phone</th>
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<table>
<thead>
<tr>
<th>GSU/AUX Transformer I.D.</th>
<th>Current Tap Setting</th>
<th>Tap Setting Range</th>
<th>Transformer Impedence (OA Base)</th>
</tr>
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<tbody>
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Dev. February, 2001
**Southwest Power Pool**

**Generator Unit Transformer Tap Setting Change Request**

Instructions: Control Area Operator shall complete information necessary to let affected Generator Owner/Operator know of needed Generator Unit Transformer settings changes.

<table>
<thead>
<tr>
<th>Generator Owner/Operator</th>
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<tbody>
<tr>
<td>Generating Station</td>
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<tr>
<td>Control Area</td>
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<tr>
<td>Date</td>
<td></td>
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<tr>
<td>Contact Name (Control Area)</td>
<td></td>
</tr>
<tr>
<td>Contact Phone (Control Area)</td>
<td></td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>GSU/AUX Transformer I.D.</th>
<th>Current Tap Setting</th>
<th>New Tap Setting</th>
<th>Technical Justification for Tap Setting Change</th>
</tr>
</thead>
<tbody>
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Dev. February, 2001
Southwest Power Pool
Generator Units Exempt from Tap Setting Reporting Procedures

Instructions: Generator Owner/Operators shall fill out information for all units under their control that are exempt from Transformer Tap Setting Procedures. The criteria that is met must also be documented.

<table>
<thead>
<tr>
<th>Generator Owner/Operator</th>
<th>Control Area</th>
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<tbody>
<tr>
<td>Date</td>
<td></td>
</tr>
<tr>
<td>Contact Name</td>
<td>Contact Phone</td>
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<tr>
<td>(Control Area)</td>
<td>(Control Area)</td>
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<table>
<thead>
<tr>
<th>Generating Station</th>
<th>Unit #</th>
<th>Exemption Criteria Met</th>
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</table>
Southwest Power Pool
Voltage Regulator Control Setting Status Report

Instructions: Generator Owner/Operators shall fill out information for all units under their control.

<table>
<thead>
<tr>
<th>Generator Owner/Operator</th>
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</thead>
<tbody>
<tr>
<td>Generating Unit</td>
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<tr>
<td>Date</td>
<td></td>
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<tr>
<td>Contact Name</td>
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<td>Contact Phone</td>
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<table>
<thead>
<tr>
<th>Generating Control</th>
<th>Control Setting</th>
<th>Generator Short Term Capability</th>
<th>Protective Relay Setting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overexcitation Limiter</td>
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<tr>
<td>Underexcitation Limiter</td>
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<tr>
<td>Volts/Hertz Limiter</td>
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Dev. February, 2001
By SPP GWG
Southwest Power Pool
Generator Governor Characteristic Reporting

Instructions: Generator Owner/Operators shall fill out information for all units under their control.

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<tr>
<th>Generator Owner/Operator</th>
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<tbody>
<tr>
<td>Generating Unit</td>
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<tr>
<td>Last Updated</td>
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<td>Contact Name</td>
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<td>Contact Phone</td>
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<thead>
<tr>
<th>Governor Control</th>
<th>Control Setting</th>
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<tbody>
<tr>
<td>Speed Regulation</td>
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</table>

Dev. February, 2001
By SPP GWG
Southwest Power Pool  
Non-Functioning Governor Controls

Instructions: Generator Owner/Operators shall fill out information for all units under their control that has a non-functioning or a blocked speed/load governor control.

<table>
<thead>
<tr>
<th>Generator Owner/Operator</th>
<th>Last Updated</th>
<th>Contact Name</th>
<th>Contact Phone</th>
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<tbody>
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<thead>
<tr>
<th>Generating Station</th>
<th>Unit</th>
<th>Governor Status (Blocked/Non-functioning)</th>
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Dev. February, 2001  
By SPP GWG
Southwest Power Pool
ENGINEERING AND OPERATION COMMITTEE
Recommendation to the Board of Directors
October 17, 2001

ADOPTION OF SPP CRITERIA 8.0

Background
To be recognized as a NERC-certified control area, NERC Control Area Criteria requires that the entity be confirmed by the Regional Council in which it resides and that it meets the requirements of the criteria. The NERC Control Area Certification Procedure provides for a process whereby a candidate is evaluated against the NERC Control Area Criteria. The procedure also allows NERC Regions to adopt specific requirements and guidelines that can be used in conjunction with the NERC procedure. All Regionally adopted control area certification procedures must be submitted to the NERC Operating Committee (OC) for approval. At its February 22-23, 2000 meeting, the SPP Security Working Group (SWG) formed the Control Area Certification Task Force (CACTF) to develop specific procedures and requirements for entities seeking control area certification within the SPP Region.

Recent Activity
Due to a request by an entity to be certified as a control area within the SPP Region by June 1, 2001, the development of SPP control area certification procedures was expedited. The CACTF offered certification procedures to the SWG for discussion during its December 13, 2000 conference call meeting. During that conference call, the SWG asked that SPP Criteria be developed to refer to these certification procedures. Criteria 8.0 and the certification procedures were then approved via e-mail vote by the SWG on December 18, 2000. The certification procedures were then distributed to the SPP Engineering and Operating Committee (EOC) for their approval. The EOC approved the procedures via e-mail vote on January 24, 2001. Approval of Criteria 8.0 was deferred until the March 19-20, 2001 EOC meeting.

Analysis
The CACTF reviewed existing SPP Criteria to assess what requirements control areas in the SPP Region must meet in addition to the NERC requirements. Any part of the SPP Criteria that was identified as a control area responsibility was included in the certification procedures as an SPP specific requirement.

Conclusion
The SWG reviewed the certification procedures developed by the CACTF and unanimously agreed to implement them on an interim basis until they could be approved by the NERC OC. To facilitate expedited changes to the procedures as necessary, the SWG concluded that the procedures should be treated as business practices and should not be included in SPP Criteria. The SWG believed that SPP Criteria should merely state that an entity seeking control area recognition must be certified by SPP according to those procedures.

Recommendation
The Engineering and Operating Committee is recommending that the attached language be incorporated into SPP Criteria as Criteria 8.0.
Approved
Security Working Group December 2000
Engineering and Operating Committee March 2001

Action Requested
The Board of Directors is requested to approve the attached SPP Criteria 8.0 as recommended by the EOC.
8.0 CONTROL AREA CERTIFICATION

An entity seeking to be recognized as a Control Area operating within SPP must be a member of SPP and must attain and maintain Control Area certification. Control Area certification will be performed by SPP pursuant to NERC approved Control Area Criteria and certification procedures to be developed and maintained by the Security Working Group. These certification procedures will be publicly available by posting on the SPP home page.
SPP Control Area Criteria and Certification Procedures V1.0

I. NERC Control Area Criteria

Criteria Subsections

A. Confirmation as a Control Area
B. Criteria

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

A. Confirmation as a Control Area

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

B. Criteria For A Control Area

NERC Criteria

1. Generation. The CONTROL AREA shall operate generation or have the necessary contracts to operate generation to:
   1.1. Meet its area instantaneous demand, INTERCHANGE SCHEDULE, OPERATING RESERVE, and Reactive resource requirements.
   1.2. Provide its frequency bias obligations.
   1.3. Balance its NET ACTUAL INTERCHANGE and NET SCHEDULED INTERCHANGE
   1.4. Use tie-line bias control (unless doing so would be adverse to system or the INTERCONNECTION reliability).
   1.5. Comply with Control Performance and Disturbance Control Standards (see Policy 1E, “Generation Control and Performance – Performance Standard”)
   1.6. Repay its INADVERTENT INTERCHANGE balance. (see Policy 1F, “Generation Control and Performance – Inadvertent Interchange”)
2. **Metering.** The CONTROL AREA shall have meters on all tie lines with adjacent CONTROL AREAS to record actual interchange (MW and MWH) in real time. INTERCHANGE meters shall be at a location common to both CONTROL AREAS, and shall provide identical values with opposite signs to both CONTROL AREAS.

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

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

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

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

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

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

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

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

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

**SPP Criteria**

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

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

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

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

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

6. A Control Area shall reduce their area load during a generation deficiency until the available generation is sufficient to match their area load, in accordance to SPP Criteria 7.3.
7. A Control Area shall have a detailed black start plan and train personnel in its implementation in accordance to SPP Criteria 9.0. The plan shall be on file at the SPP office.

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

II. Control Area Certification Procedures

Background

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

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

Certification Process

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

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

While not specifically referenced in this document, as with all NERC Standards, SPP’s specific requirements and guidelines are used in conjunction with (but not in place of) the NERC Control
Area Certification Procedure. The Certification Process shall be completed in a maximum allowable time of six months from the initiation of the process.

Control Area Certification Procedure

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

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

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

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

5. SPP will provide forms and questionnaires that will be used by all entities involved in the Procedure. These forms and questionnaires will be used to address the Applicant’s capabilities and actions as they relate to previously established Control Area requirements. The following list of entities will be recipients of the questionnaires as each is a source of necessary certification information and data:
   - Applicant (i.e. entity seeking Control Area certification)
   - Control Areas physically interconnected with the Applicant
   - SPP Security Coordinator

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

7. SPP will select and assemble a balanced Certification Review Team to be charged with the responsibility of determining if the Applicant meets NERC and SPP Control Area Criteria. The Review Team will typically consist of the following:
- SPP Engineering and Operating Committee member (Review Team chair)
- SPP Security Working Group member
- SPP Transmission Assessment Working Group member
- SPP Commercial Practices Committee member
- SPP Security Coordinator
- Representative from NERC
- Representative from another NERC region

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

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

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

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

12. The Review Team will re-evaluate the Applicant in the deficient areas if the corrective actions occur within the timetable. The Review Team will be responsible for any follow-up work that is needed and continue such work until a “certify/deny” decision is made.
13. The SPP Board will consider the Review Team’s recommendation and approve or disapprove the recommendation.

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

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

Compliance and Evaluation

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

Adjacent Control Areas

- Has the Applicant coordinated emergency operating plans with you?
Security Coordinator

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

SPP Region

- Is the Applicant a member and signed the membership agreement?
Background
The NERC Compliance Program was developed to ensure compliance with the NERC Planning Standards and Operating Policies and Standards. This Program includes Standards to ensure that the reliability of the interconnected bulk electric systems is maintained in the more competitive electricity markets. These Standards define what the reliability requirements are to those who plan, operate and use the systems. SPP, as a region of NERC, is responsible to comply with these Standards.

Recent Activity
The Model Development Working Group (MDWG) reviewed NERC Planning Standard II.C “Methodology (ies) for determining electrical facility ratings” and compared it to the SPP Criteria. The Standards II.C Measurement 1 (M1) includes methods for rating series reactive elements, shunt reactive elements, and electrical energy storage devices which are not contained in the SPP Criteria.

Analysis
The MDWG reviewed the SPP Criteria 12.0 Rating of Generating Equipment. The MDWG made minor modifications to the existing criteria and added two new subsections. The new additions to the criteria were developed to include the requirements of the modified NERC Planning Standard II.C Compliance Template Measurement 1.

Conclusion
NERC requires that each facility owner shall document the methodology used to determine their electrical facility ratings which include series and shunt reactive elements and electrical energy storage devices. The additional requirements of NERC have been incorporated into the new criteria such that SPP and its members maintain an acceptable level of compliance in accordance with NERC’s current Standards and Measures.

Recommendation
The EOC recommends that the Board of Directors approve the modified Criteria 12.0 as attached.

Approved
The recommendations were approved by the MDWG March 2001
The recommendations were approved by the EOC March 2001

Action Requested
Approve the modifications to Criteria 12.0, Electrical Facility Ratings.
NERC Planning Standard II.C. Compliance Template Measurement 1

**Brief Description**
Methodology(ies) for determining electrical facility ratings.

**Category**
Documentation

**Section**
II. System Modeling Data Requirements  
C. Facility Ratings

**Standard**
S1. Electrical facilities used in the transmission and storage of electricity shall be rated in compliance with applicable Regional, subregional, power pool, and individual transmission provider/owner planning criteria.

**Measurement**
M1. Facility owners shall document the methodology (or methodologies) used to determine their electrical facility ratings. Further, the methodology(ies) shall be compliant with applicable Regional, subregional, power pool, and individual transmission provider/owner planning criteria.

The documentation shall include the methodology(ies) used to determine transmission facility ratings for both normal and emergency conditions. It shall also include methods for rating:

1. Transmission lines,
2. Transformers,
3. Series and shunt reactive elements,
4. Terminal equipment (e.g., switches, breakers, current transformers, etc.), and
5. Electrical energy storage devices (e.g., superconducting magnetic energy storage (SMES) system).

The rating of a transmission circuit shall not exceed the rating(s) of the most limiting element(s) in the circuit, including terminal connections and associated equipment. In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the rating for that facility.

Facility rating deviations from the methodology(ies), such as providing a consistent basis for jointly-owned facilities and unique applications, shall be documented. Ratings of jointly-owned facilities shall be coordinated and provided on a consistent basis.

The documentation shall identify the assumptions used to determine each of the facility ratings, including references to industry rating practices and standards (e.g., ANSI, IEEE, etc.). Seasonal ratings and variations in assumptions shall be included.

The documentation of the methodology(ies) used to determine transmission facility ratings shall be provided to the Regions and NERC on request (five business days).

**Applicable to**
Facility owners.

**Items to be Measured**
Methodology(ies) used for determining facility ratings.

**Timeframe**
On request (five business days).
Levels of Non-Compliance

Level 1
Facility rating methodologies do not address or do not meet the applicable criteria for one of the five facility types listed in the above Measurement M1.

Level 2
Facility rating methodologies do not address or do not meet the applicable criteria for two of the five facility types listed in the above Measurement M1.

Level 3
Facility rating methodologies do not address or do not meet the applicable criteria for three or more of the five facility types listed in the above Measurement M1.

Level 4
No facility rating methodology(ies) were provided.

Compliance Monitoring Responsibility
Regions.

Reviewer Comments on Compliance Rating

_________________________________________________________

_________________________________________________________

_________________________________________________________
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12.0 ELECTRICAL FACILITY RATINGS

12.1 Rating of Generating Equipment

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

12.1.1 Capability Test

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

<table>
<thead>
<tr>
<th>Unit Type</th>
<th>Settling Period</th>
<th>Test Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam &gt; 100 MW net</td>
<td>2.0 hours</td>
<td>2.0 hours</td>
</tr>
<tr>
<td>Steam &lt; 100 MW net</td>
<td>1.0 hour</td>
<td>1.0 hour</td>
</tr>
<tr>
<td>All other units</td>
<td>0.0 hour</td>
<td>1.0 hour</td>
</tr>
</tbody>
</table>

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

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

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

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

12.1.5  Procedures For Establishing Capability Ratings

12.1.5.1  External Factors

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

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

c. The fuel used during testing shall be the general type expected to be used during peak
load conditions or adjustments made to test data if an alternate fuel is used.

d. Net Capability is the net power output which can be obtained for the period specified on a seasonally adjusted basis with all equipment in service under average conditions of operation and with the equipment in an average state of maintenance. Deductions from net capability shall not be made for equipment temporarily out of service for normal maintenance or repairs.

e. The seasonal net capability shall be determined separately for each generating unit in a power plant where the input to the prime mover of the unit is independent of the others, except that in the event multiple unit plant capability is limited by fuel limitations, transmission limitations or other auxiliary devices or equipment, each unit shall be assigned a rating by apportioning the combined capability among the units. The seasonal net capability shall be determined as a group for common header sections of steam plants or multiple unit hydro plants, and each unit shall be assigned a rating by apportioning the combined capability among the units.
12.1.5.2 Seasonality

a. The summer season is defined by the months June, July, August and September. The winter season is defined by the months December, January and February. The adjustments required to develop seasonal net capabilities are intended to include seasonal variations in ambient temperature, condenser cooling water temperature and availability, fuel changes, quality and availability, steam heating loads, reservoir levels, and scheduled reservoir discharge.

b. The total seasonal net capability rating shall be that available regularly to satisfy the daily load patterns of the member and shall be available for a minimum of four continuous hours taking into account possible fuel curtailments and thermal limits.

c. The seasonal net capability of each generating unit shall be based upon a set of conditions, referred to as the "Rating Conditions" for that unit. This set of conditions is determined by the geographical location of the unit, and is composed of three or four factors, depending upon the type of unit. The three factors which can affect most generating units are: Ambient dry-bulb temperature, Ambient wet-bulb temperature and Barometric pressure. Condensing steam turbines which obtain condenser cooling water from a lake, river, or comparable source have a fourth factor: Condenser cooling water source temperature.

d. The Rating dry-bulb and wet-bulb temperatures shall be obtained from weather data provided in the most recently published American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) Fundamentals Handbook. The handbook is published every four years; 1989, 1993, etc., and is based on 15 years of historical weather data where available. If the generating station is within 30 miles of the nearest weather station reported in the handbook, then these temperatures will be those for the nearest station. For all other stations, rating temperatures shall be determined by interpolating between weather stations using plant latitude and longitude. Selected pages of the "Weather Data" chapter of the handbook are reprinted in the Appendix with permission of ASHRAE. The steps to be used for interpolating weather data and correcting for elevation are also presented in the Appendix.
e. If experience for a given unit suggests otherwise, members may optionally use their own site specific temperature data if accurate hourly data is available to allow calculation of the temperature levels as defined in the Criteria. Site specific data shall contain both dry-bulb and wet-bulb temperatures.

f. The dry-bulb temperature for summer rating of equipment shall be taken as that which is equaled or exceeded 1% of the total hours during the months of June through September for the plant's geographical location. The wet-bulb temperature for the summer rating shall be the "mean coincident wet-bulb" temperature corresponding to the above dry-bulb temperature. These two temperatures are listed together under the "1%" heading in the weather data table in the Appendix.

g. The minimum dry-bulb temperature for winter testing and rating shall be taken as that which is equaled or exceeded 99% of the total hours during the months of December through February for the plant's geographical location. The wet-bulb temperature is not significant for the winter rating and can be disregarded. The winter dry-bulb temperature is listed under the "99%" heading in the weather data table in the Appendix.

h. Standard barometric pressure for a plant site shall be determined for each plant elevation by linearly interpolating the pressure table provided in the Appendix.

i. For those units using a lake or river as a source of condenser cooling water, the summer standard inlet temperature is the highest water inlet temperature during the hottest month of the year, averaged over the past ten years.

j. Ambient wet-bulb temperature and condenser cooling water temperature are generally not significant factors in adjusting cold weather capability of generating units. Shall special situations arise in which these temperatures are required, reasonable estimates for temperatures occurring coincidentally with the winter rating dry-bulb temperature as defined in the Criteria shall be used.

12.1.5.3 Rating Adjustments

a. The rated net capability of a unit may be above or below the actual tested net generation as a result of adjustments for Rating Conditions, with the exception of units with winter season ratings greater than their summer rating.

12-5
For these units, the winter season rated net capability shall be no greater than the actual tested net generation. No rating adjustment for ambient conditions shall be made.

b. Seasonal net capability shall not be reduced to provide regulating margin or spinning reserve. It shall reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period.

c. Extended capability of a unit or plant obtained through bypassing of feed-water heaters, by utilizing other than normal steam conditions, by abnormal operation of auxiliaries in steam plants, or by abnormal operation of combustion turbines or diesel units may be included in the seasonal net capability if the following conditions are met; a) the extended capability based on such conditions shall be available for a period of not less than four continuous hours when needed and meets the other restrictions, and b) appropriate procedures have been established so that this capability shall be available promptly when requested by the system operator.

d. The seasonal net capability established for nuclear units shall be determined taking into consideration the fuel management program and any restrictions imposed by governmental agencies.

e. The seasonal net capability established for hydro electric plants, including pumped storage projects, shall be determined taking into consideration the reservoir storage program and any restrictions imposed by governmental agencies and shall be based on median hydro conditions.

f. The seasonal net capability established for run-of-the-river hydroelectric plants shall be determined using historical hydrological data on a monthly basis.

12.2 Rating of Transmission Circuits

Each SPP member shall rate transmission circuits operated at 69 kV and above in accordance with this criteria. A transmission circuit shall consist of all elements load carrying between circuit breakers or the comparable switching devices. Transformers with both primary and secondary windings energized at 69 kV or above are subject to this criteria. All circuit ratings shall be computed with the system operated in its normal state (all lines and buses in-service, all breakers with normal status, all loads served.
from their normal source). The circuit ratings will be specified in "MVA" and are taken as the minimum ratings of all of the elements in series. The minimum circuit rating shall be determined as described in this criteria and members shall maintain transmission right-of-way to operate at this rating. However, SPP members may use circuit ratings higher than these minimums. Each element of a circuit shall have both a normal and an emergency rating. For certain equipment, (switches, wave traps, current transformers and circuit breakers), these two ratings are identical and are defined as follows:

a. **NORMAL RATING:** Normal circuit ratings specify the level of power flow that facilities can carry continuously without loss of life to the facility involved.

b. **EMERGENCY RATING:** Emergency circuit ratings specify the level of power flow that a facility can carry for the time sufficient for adjustment of transfer schedules, generation dispatch, or line switching in an orderly manner with acceptable loss of life to the facility involved.

At a minimum, each member shall compute summer and winter seasonal ratings for each circuit element. The summer season is defined by the months June, July, August and September. The winter season is defined by the months December, January, February and March. The seasonal rating shall be based upon an ambient temperature (either maximum or average) developed using the methodology described in Appendix A. A member may elect to compute a third set of seasonal ratings for the remaining months of the year (April, May, October and November). If that election is not made, summer ratings shall be used for these remaining months.

### 12.2.1 Power Transformer

Power transformer ratings are discussed in ANSI/IEEE C57.92-1981, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers Up to and Including 100 MVA with 55°C or 65°C Average Winding Rise and in IEEE Standard C57.115-1991, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers Rated in Excess of 100 MVA (65EC Winding Rise). Every transformer has a distinct temperature rise capability used in setting its nameplate rating (either 55 °C or 65°C). These temperature rise amounts reflect the average winding temperature rise over ambient that a transformer may operate on a continuous basis and still provide normal life expectancy.
12.2.2.1 Normal Rating
The normal circuit rating for power transformers shall be its highest nameplate rating. The nameplate rating shall include the effects of forced cooling equipment if it is available. For multi-rated transformer (OA/FA, OA/FA/FA, OA/FOA/FOA, OA/FA/FOA) with all or part of forced cooling inoperative, nameplate rating used is based upon the maximum cooling available for operation. Normal life expectancy will occur with a transformer operated at continuous nameplate rating.

12.2.1.2 Emergency Rating
When operated for one or more load cycles above nameplate rating, the transformer insulation deteriorates at a faster rate than normal. The emergency circuit rating for power transformers shall be a minimum of 100% of its highest nameplate rating. Member systems may use a higher emergency rating if they are willing to experience more transformer loss-of-life.

12.2.1.3 Loss of Life
Using Table 3 in ANSI/IEEE C57.92-1981, a 65°C rise transformer can operate at 120% for an 8 hour peak load cycle and will experience a 0.25% loss of life. If a 65°C rise transformer experiences 4 incidents where it operates at or below 120% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year. Using Table 5 in ANSI/IEEE C57.92-1981, a 55°C rise transformer can operate at 123% for an 8 hour peak load cycle and will experience a 0.25% loss of life. Likewise, if a 55°C rise transformer experiences 4 incidents where it operates at or below 123% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year.

12.2.1.4 Ambient Temperature
Average ambient temperature is an important factor in determining the load capability of a transformer since the temperature rise for any load must be added to the ambient to determine operating temperature. Transformers designed according to ANSI standards use a 30°C average ambient temperature (average temperature for 24 consecutive hours) when setting nameplate rating. Transformer overloads can be increased at lower average ambient temperatures and still experience the same loss of life. This allows seasonal ratings with higher normal and emergency ratings.
However, this circuit rating criteria does not call for seasonal transformer ratings. Using Tables 3 and 5 in ANSI/IEEE C57.92-1981, transformers can be loaded above 110% and experience no loss of life when the average ambient temperature is below 78°F. By not having seasonal ratings, the four occurrences that contribute to loss of life are limited to days when the average ambient temperature exceeds 78°F. The Power Transformer Rating Factors include:

a. Nameplate rating, normal loss of life for 55°C and 65°C rise transformers with cooling equipment operating.
b. Average ambient temperature, 30°C.
c. Equivalent load before peak load, 90% of nameplate rating.
d. Hours of peak load, 8 hour load cycle.
e. Acceptable annual loss of life, 1%.

12.2.2 Overhead Conductor
Overhead conductor ratings are discussed in IEEE Standard 738-1993, IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors. Ampacity values are to be determined using the fundamental heat balance equation outlined in the House and Tuttle method. Because of the amount and complexity of the equations, this method lends itself to computer application. The recommended computer programs to be used for this calculation either include the BASIC program listed in Annex A of IEEE Standard 738-1993 or an equivalent program, such as the DYNMAP program which is part of the EPRI TLWorkstation™ software package. While tables and graphs may be convenient to use, they fail to take into account the geographic location of the line and often lack either the desired ambient temperature and/or the desired conductor temperature. The use of tables and graphs is not acceptable.

12.2.2.1 Conductor Properties
Some computer programs used to compute ampacity values have a conductor property library whereby a user simply specifies the conductor code name and the program will search the conductor property file and select the proper input properties. Those using the BASIC program from Annex A of IEEE Standard 738-1993 or another computer program that does not have a conductor property library will obtain conductor properties
from an appropriate data source (Aluminum Electrical Conductor Handbook, EPRI Transmission Line Reference Book 345 kV and Above, Westinghouse Transmission and Distribution Book, etc.).

12.2.2.2 Line Geographic Location
These factors specify the location of the line, its predominant direction and its predominant inclination. These numbers can either be line specific or they can represent a general line within the control area. One ambient temperature shall be agreed upon for tie lines traversing several geographic areas and interconnections among different control areas.

12.2.2.3 Radiation Properties
The two radiative properties of conductor material are solar absorptivity and infrared emissivity.

**Solar Absorptivity**

The fraction of incident solar radiant energy that is absorbed by the conductor surface. This value shall be between 0 and 1. Recommended values are given in the following tables:

<table>
<thead>
<tr>
<th>COOPER CONDUCTORS</th>
<th>ALUMINUM CONDUCTORS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oxidation Level</strong></td>
<td><strong>Absorptivity</strong></td>
</tr>
<tr>
<td>None</td>
<td>0.23</td>
</tr>
<tr>
<td>Light</td>
<td>0.5</td>
</tr>
<tr>
<td>Normal</td>
<td>0.7</td>
</tr>
<tr>
<td>Heavy</td>
<td>1.0</td>
</tr>
</tbody>
</table>

**Infrared Emissivity**  
The ratio of infrared radiant energy emitted by the conductor surface to the infrared radiant energy emitted by a blackbody at the same temperature. This value shall be between 0 and 1. Recommended values are given in tables below:

<table>
<thead>
<tr>
<th>Copper Conductors</th>
<th>Emissivity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oxidation Level</td>
<td></td>
</tr>
<tr>
<td>None</td>
<td>0.03</td>
</tr>
<tr>
<td>Light</td>
<td>0.3</td>
</tr>
<tr>
<td>Normal</td>
<td>0.5</td>
</tr>
<tr>
<td>Heavy</td>
<td>0.8</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Aluminum Conductors</th>
<th>Emissivity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service Years</td>
<td></td>
</tr>
<tr>
<td>0</td>
<td>0.23</td>
</tr>
<tr>
<td>5-10</td>
<td>0.82</td>
</tr>
<tr>
<td>10-20</td>
<td>0.88</td>
</tr>
<tr>
<td>&gt;20</td>
<td>0.90</td>
</tr>
</tbody>
</table>


**12.2.2.4 Weather Conditions**
Ambient temperature represents the maximum seasonal temperature the line may experience for summer and winter conditions. Appendix A contains a methodology to compute maximum ambient temperature. Wind speed is assumed at 2 ft/sec (1.4 mph) or higher. Wind direction is assumed perpendicular to the conductor.

**12.2.2.5 Maximum Conductor Temperature**
The selection of a maximum conductor temperature affects both the operation and design of transmission lines. Existing transmission lines were designed to meet some operating standard that was in effect at the time the line was built. That standard specified the maximum conductor temperature which maintained acceptable ground clearance while allowing for acceptable loss of strength. Over time, the required amount of ground clearance and the maximum conductor temperature needed to maintain acceptable ground clearance have changed.
The changes are reflected in the revisions that have been made to the National Electric Safety Code (NESC) over the years. Although this Criteria specifies a maximum conductor temperature that could be met by current line design practices, consideration must be given to existing lines that were built according to an earlier standard. This Circuit Rating Criteria specifies a maximum conductor temperature (for both normal and emergency operating conditions) that shall be used for seasonal circuit ratings. For those existing lines that were designed to meet an earlier standard, it is the responsibility of the line owner to establish a rating that is consistent with the NESC design standards being practiced at the time the line was built. This Criteria specifies the use of maximum conductor temperatures that either maintain acceptable ground clearance requirements from earlier NESC's or meet the temperature requirements in section 3.6.2.6, whichever is lower.

12.2.2.6 Determination of Maximum Conductor Temperature
The maximum conductor temperature for normal ratings may be limited by conductor clearance concerns. Normal ratings are at a level where loss of strength is not a concern. The maximum conductor temperature for emergency ratings have both conductor clearance and loss of strength concerns. By setting a maximum conductor temperature and the length of time a conductor may operate at this temperature, the maximum allowable loss of strength over the life of the conductor is prescribed. Unless conductor clearance concerns dictate otherwise, at least the following maximum conductor temperatures shall be used. This allows for the efficient utilization of the transmission system while accepting minimal risk of loss of conductor strength during emergency operating conditions. These conductor temperatures are a result of the examination of SPP members practices.
<table>
<thead>
<tr>
<th>Material</th>
<th>Normal Rating</th>
<th>Emergency Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACSR</td>
<td>85°C</td>
<td>100°C</td>
</tr>
<tr>
<td>ACAR</td>
<td>85°C</td>
<td>100°C</td>
</tr>
<tr>
<td>Copper</td>
<td>85°C</td>
<td>100°C</td>
</tr>
<tr>
<td>Copperweld</td>
<td>85°C</td>
<td>100°C</td>
</tr>
<tr>
<td>AAC</td>
<td>85°C</td>
<td>100°C</td>
</tr>
<tr>
<td>AAAC</td>
<td>85°C</td>
<td>100°C</td>
</tr>
<tr>
<td>SSAC</td>
<td>200°C</td>
<td>200°C</td>
</tr>
</tbody>
</table>

**Note:** Annealing of copper and aluminum begins near 100°C.

### 12.2.2.7 Hours of Operation at Emergency Rating

The effect of conductor heating due to operating at the maximum temperature during emergency conditions is cumulative. If a conductor is heated under emergency loading for 4 hours 8 times during the year, the total effect is nearly the same as heating the conductor continuously at the temperature for 32 hours. Using a useful conductor life of 30 years, the conductor will have been heated to the maximum temperature for 1000 hours. For an all aluminum conductor (AAC), this results in a 7% reduction from initial strength. Since the steel core of an ACSR conductor is essentially unaffected by the temperature range considered for emergency loadings, for an ACSR conductor, this results in a 3% reduction from initial strength. Both of these amounts are acceptable loss of strength. The daily load cycle for operating at the emergency rating shall not exceed 4 hours. This load cycle duration for conductors operating at the emergency rating is more restrictive than power transformers because power transformers have a delay in the time required to reach a stable temperature following any change in load (caused by a thermal lag in oil rise) and because seasonal ratings shall allow transmission lines to achieve a maximum conductor temperature throughout the year.
not just days when the ambient exceeds 78°F.

12.2.3 Underground Cables
Ampacities are calculated by solving the thermal equivalent of Ohm's Law. Conceptually, the solution is simple, however the careful selection of the values of the components of the circuit is necessary to ensure an accurate ampacity calculation. The recognized standard for almost all steady-state ampacity calculations, in the United States, is taken from a publication, "The Calculation of the Temperature Rise and Load Capability of Cable Systems," by J.H. Neher and M.H. McGrath, 1957, hereafter referred to as the Neher-McGrath method. The procedure is relatively simple to follow and has been verified through testing. In recent years, some of the parameters have been updated, but the method is still the basis of all ampacity calculations.

12.2.3.1 Cable Ampacity
Cable ampacity is dependent upon the allowable conductor temperature for the particular insulation being used. Conductor temperature is influenced by the following factors:
- Peak current and load-cycle shape;
- Conductor size, material and construction;
- Dielectric loss in the insulation;
- Current-dependent losses in conductor, shields, sheath and pipe;
- Thermal resistances of insulation, sheaths and coverings, filling medium, pipe or duct and covering, and earth;
- Thermal capacitances of these components of the thermal circuit;
- Mutual-heating effects of other cables and other heat sources; and
- Ambient earth temperatures.
Both steady-state and emergency ampacities depend upon these factors, although emergency ratings have a greater dependency upon the thermal capacitances of each of the thermal circuit components.

12.2.3.2 Conductor Temperature
The maximum allowable conductor temperature is 85°C for high-pressure fluid-filled (HPFF), pipe-type cables and 90°C for crosslinked, extruded-dielectric cables.
The table below summarizes allowable conductor temperatures for different insulation materials. Two values are given for each cable insulation. The higher temperature may be used if the thermal environment of the cable is well-known along the entire route, or if controlled backfill is used, or if fluid circulation is present in an HPFF circuit. The maximum conductor temperatures allowed under steady-state conditions are limited by the thermal aging characteristics of the insulation structure of the cable. For emergency-overload operating conditions, maximum conductor temperatures are also limited by the thermal aging characteristics. The temperature is also limited by the melting temperature range of the insulation structure of the cable, its deformation characteristic with temperatures, restraints imposed by the metallic shield, deformation characteristic of the jacket, and the decrease in ac and impulse strengths with increases in temperature.

<table>
<thead>
<tr>
<th>Insulation Material</th>
<th>Maximum Temperature</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Normal</td>
</tr>
<tr>
<td>Impregnated paper (AEIC CS2-90 for HPFF and HPGF)</td>
<td>85°C</td>
</tr>
<tr>
<td>(AEIC CS4-79 for SCLF)</td>
<td>(75°C)</td>
</tr>
<tr>
<td>Laminated paper-polypropylene (AEIC CS2-90)</td>
<td>85°C</td>
</tr>
<tr>
<td></td>
<td>(75°C)</td>
</tr>
<tr>
<td>Crosslinked polyethylene (AEIC CS7-87)</td>
<td>90°C</td>
</tr>
<tr>
<td></td>
<td>(80°C)</td>
</tr>
<tr>
<td>Ethylene-propylene rubber (AEIC CS6-87)</td>
<td>90°C</td>
</tr>
<tr>
<td></td>
<td>(80°C)</td>
</tr>
<tr>
<td>Electronegative gas/spacer</td>
<td>Consult manufacturer for specific designs</td>
</tr>
</tbody>
</table>

* This limit may need to be reduced to prevent damage due to thermal expansion of the insulation.
12.2.3.3 Ambient Temperature

The ambient temperature is measured at the specified burial depth for buried cables and the ambient air temperature is used for cables installed above ground. IEC Standard 287-1982 (2-5) recommends that in the absence of national or local temperature data the following should be used:

<table>
<thead>
<tr>
<th>Climate</th>
<th>Ambient Air Temperature °C</th>
<th>Ambient Ground Temperature °C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tropical</td>
<td>55</td>
<td>40</td>
</tr>
<tr>
<td>Sub-tropical</td>
<td>40</td>
<td>30</td>
</tr>
<tr>
<td>Temperature</td>
<td>25</td>
<td>20</td>
</tr>
</tbody>
</table>

The electrical resistance is composed of conductor dc resistance, ac increments due to skin and proximity effects, losses due to induced currents in the cable shield and sheath and induced magnetic losses in the steel pipe. Heat generated in the cable system will flow to ambient earth and then to the earth surface. This heat passes through the thermal resistances of the cable insulation, cable jacket, duct or pipe space, pipe covering and soil. Adjacent heat sources, such as other cables or steam mains, will provide impedance to the heat flow and thus reduce cable ampacity. Further information concerning the components of the ampacity calculations are summarized in Appendix B and fully detailed in the EPRI Underground Transmission Systems Reference Book. An example calculation, from the EPRI book, is also provided in Appendix B.

12.2.4 Switches

Appendix C contains a discussion on developing ratings for switches. In general, switches have seasonal ratings that are a function of the maximum ambient temperature. A switch part class designation is used to differentiate loadability curves that give factors which can be multiplied by the rated continuous current of the switch to determine temperature adjusted normal and 4 hour emergency ratings.
The summer normal and emergency switch ratings can be computed by selecting the appropriate loadability factor curve for the switch part class, reading the loadability factors that are appropriate for the summer maximum ambient temperature ($40^\circ C$ or the summer maximum ambient temperature determined in Appendix A), and multiplying the continuous current ratings by the loadability factor. The switch winter normal and emergency ratings can be computed by multiplying the continuous current rating by the normal and emergency loadability factors that are appropriate for the winter maximum ambient temperature ($0^\circ C$ or the winter maximum ambient temperature determined in Appendix A). Appendix C contains loadability factor curves (both normal and emergency) for various switch part classes. The ANSI/IEEE standard referenced in Appendix C allows for emergency ratings to be greater than normal ratings. This Criteria does not require the emergency rating to be greater than the normal rating.

### 12.2.5 Wave Traps

Appendix D contains a discussion on developing ratings for wave traps. The two types of wave traps are the older air-core type and the newer epoxy-encapsulated type. In general, both types have a continuous current rating based on a $40^\circ C$ maximum ambient temperature. Both types have a loadability factor that can be used to determine seasonal ratings that are a function of the maximum ambient temperature. However, the older air-core type has another loadability factor that can be used to determine a four-hour emergency rating that is also a function of the maximum ambient temperature. The newer epoxy encapsulated type does not have an emergency rating.

### 12.2.6 Current Transformers

Appendix E contains a discussion on developing ratings for current transformers. The two types of current transformers are the separately-mounted type and the bushing type. In general, both types have a continuous current rating based on a $30^\circ C$ average ambient temperature.

#### 12.2.6.1 Separately Mounted Current Transformers

The separately-mounted type has an ambient-adjusted continuous thermal current rating factor that can be multiplied by the rated primary current of the current transformer to determine seasonal ratings.
Separately-mounted current transformers do not have emergency ratings.

### 12.2.6.2 Bushing Current Transformers

Bushing current transformers are subject to and influenced by the environment of the power apparatus in which they are mounted. Bushing current transformers can be located within circuit breakers and power transformers. Since bushing current transformers are subject to the environment within the power apparatus, they do not have ambient adjusted continuous thermal current rating factors. Rather, if the primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer, this restricts the breaker or power transformer to operate below its rated current which reduces the current transformer temperature. This allows the current transformer to be operated at a continuous thermal rating factor greater than 1.0. Having a bushing current transformer whose primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer is an unusual case. However, the formula to develop the rating factor for this case is located in Appendix E. Although bushing current transformers have some short-term emergency overload capability, it must be coordinated with the overall application limitation of the other equipment affected by the current transformer loading. Consequently, this criteria does not recognize an emergency rating for bushing current transformers.

### 12.2.7 Circuit Breakers

Appendix F contains a discussion on developing ratings for circuit breakers. This discussion centers on the use of specific circuit breaker design information to set seasonal and emergency ratings. This design information is not readily available to the owners of such equipment. To use the rating methodology discussed in Appendix F would require contacting the manufacturer for detailed design information for each circuit breaker being rated. Rather than doing that, this circuit rating criteria specifies that the nameplate rating shall be used for seasonal normal and emergency ratings. The nameplate rating is based on a maximum ambient temperature of 40°C. If a circuit breaker is found to be a limiting element in a circuit and is experiencing loadings that limit operations, a member system may pursue the methodology outlined in Appendix F to determine the circuit breakers seasonal normal and emergency rating.

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### 12.2.8 Ratings of Series and Reactive Elements

The series transmission elements rating will be in amps, ohms, and MVA. The series transmission elements current (amps) rating will be taken as the minimum rating of all internal components (e.g., breakers) that are in series with the interconnected transmission circuit.
Shunt reactive elements (e.g., capacitors, reactors) MVA ratings will be based on the nominal transmission interconnecting voltage.

The documentation of the methodology(ies) used to determine the rating of series and reactive elements shall be provided to SPP and/or NERC on request within five business days.

12.2.9 Ratings of Energy Storage Devices
The available real power rating, reactive power rating, control points, and availability of each electrical energy storage device will be provided to SPP upon request. The documentation of the methodology(ies) used to rate electrical energy storage devices shall be provided to SPP and/or NERC on request within five business days.

12.2.10 Circuit Rating Issues
12.2.10.1 Dynamic (Real Time) Ratings
The calculation of static thermal ratings specified in Section 3.6.2 uses worst case thermal and operational factors and therefore apply under all conditions. Often times, these worst case thermal and operational factors do not all occur at the same time. Consequently, a static rating may understate the thermal capacity of the circuit. For operation purposes, some members have elected to monitor the factors that affect circuit ratings and use this information to set dynamic ratings. A member can develop and use a rating that exceeds the static thermal rating for operating purposes. The ratings developed by using this criteria are not intended to restrict daily operations but set a minimum rating that can be increased when factors for determining the equipment rating have changed. However, if transmission line ratings are changed dynamically, the required clearances shall still be met.
12.2.10.2 Non-Thermal Limitations
There may be instances when the flow on a transmission circuit is limited by factors other than the thermal capacity of its elements. The limit may be caused by other factors such as dynamics, phase angle difference, relay settings or voltage limited.

12.2.10.3 Tie Lines
When a tie line exists between two member systems, use of this criteria shall result in a uniform circuit rating that is determined on a consistent basis between the two systems. For tie lines between a SPP member and a non-member, the member shall follow this criteria to rate the circuit elements owned by them and shall coordinate the rating of the tie line with the non-member system such that it utilizes the lowest rating between the two systems.

12.2.10.4 Rating Inconsistencies
A member may have a contractual interest in a joint ownership transmission line whereby the capacity of the line is allocated among the owners. The allocated capacity may be based upon the thermal capacity of the line or other considerations. Members shall use good faith effort to amend their transmission line agreements to reflect the effects of new circuit ratings. There may exist other transmission agreements or regulatory mandates that use the thermal capacity of transmission circuits in allocation of cost and determination of network usage formulas (for example, the MW-mile in ERCOT). These agreements and mandates may specify a methodology and/or factors for computing thermal capacity used in the formulas. Since these amounts are only used in assignment of cost or usage responsibility and not in actual operations of the transmission system, there is no conflict with using a different set of ratings for this specific purpose.

12.2.10.5 Damaged Equipment
There may be instances when a derating of a transmission line element is required due to damaged equipment. The limit may be caused by such factors as broken strands, damaged connectors, failed cooling fans, or other damage reducing the thermal capability.
12.2.11 Reporting Requirements
Each member will administer this Criteria and will make available upon request the application of this Criteria for those facilities that impact another member (i.e. force them to curtail schedules due to line loadings, denies them access to transmission service or requires them to build new transmission facilities or pay opportunity costs to receive transmission service).
1) Change the title of Section 12.0 RATING OF GENERATING EQUIPMENT to 12.0 ELECTRICAL FACILITY RATINGS.

2) Change section 12.2.8 to 12.2.10 with the appropriate subsection changes.

3) Change section 12.2.9 to 12.2.11 with the appropriate subsection changes.

4) Add the new section 12.2.8:

   12.2.8 Ratings of Series and Reactive Elements

   The series transmission elements rating will be in amps, ohms, and MVA. The series transmission elements current (amps) rating will be taken as the minimum rating of all internal components (e.g., breakers) that are in series with the interconnected transmission circuit.

   Shunt reactive elements (e.g., capacitors, reactors) MVA ratings will be based on the nominal transmission interconnecting voltage.

   The documentation of the methodology(ies) used to determine the rating of series and reactive elements shall be provided to SPP and/or NERC on request within five business days.

5) Add the new section 12.2.9:

   12.2.9 Ratings of Energy Storage Devices

   The available real power rating, reactive power rating, control points, and availability of each electrical energy storage device will be provided to SPP upon request. The documentation of the methodology(ies) used to rate electrical energy storage devices shall be provided to SPP and/or NERC on request within five business days.
Hello Judy!

As always, Southwest Power Pool, Inc. (SPP) welcomes membership interest in our operations and we appreciate the opportunity to work with the audit team from Kansas City Power & Light, Western Resources, Entergy, OGE Energy Corporation, and American Electric Power in the reviewing our management of the commercial and market operations systems development. I was pleased with and appreciate the comments and findings of the audit team and will present your findings to the SPP Board of Directors at their October 17, 2001 meeting.

The audit team will continue to receive updates on project status from our project manager, Richard Dillon. Also, we are finalizing our backup site under the direction of the Security Working Group as described in the minutes of this group beginning with their June 1, 2000 meeting, with most recent status having been reported as recently as in their June 2001 meeting.

Again, thanks for your team’s work and we look forward to your continued involvement in assuring a high degree of quality in SPP operations.

Take Care,

[Signature]

NB:ss
Southwest Power Pool COSMOS System Project Management Review
September 25, 2001

A team of auditors from Kansas City Power & Light, Western Resources, Entergy, OGE Energy Corporation, and American Electric Power completed a review of project management procedures over the Southwest Power Pool’s (SPP) commercial/market operations system (COSMOS) currently under development. Our objectives were to determine if proper and adequate governance and project management procedures are in place for this project. We interviewed COSMOS project management personnel and reviewed key documents. We believe governance and project management procedures are adequate. This report identifies significant observations and findings from our review.

The COSMOS system is based on the Market Rules developed by the Market Settlement Working Group to support operations under FERC Order 2000. After an extensive vendor selection process, SPP contracted with Andersen Consulting (now called “Accenture”) to develop the system based on these Market Rules. The contract with Accenture outlines in detail the responsibilities of all parties, project management procedures, and the scope of work. We reviewed the contract and believe it is comprehensive and appropriately outlines the responsibilities of all parties.

As part of their project management methodology, Accenture implemented the following:

- A Steering Council and Program Management Office was established to provide executive guidance to the project. The SPP Board of Directors receives a verbal update of monthly Steering Council meetings. Program level personnel and project management personnel meet weekly to discuss project status and issues. Summaries of these meetings, including issues tracking logs, are compiled and sent to the appropriate project personnel. We believe these procedures are adequate to inform all parties of the status of the project and to escalate significant issues to the appropriate level.
- A master project plan, as well as detailed project plans, was developed. The detailed plan identifies major deliverables that will be produced. The timeline and key milestones are reviewed on a regular basis. Proposed changes to the master plan are evaluated and referred to the Steering Council. Current project status is also posted on SPP’s website.
- Accenture provided an issues tracking tool where issues are captured from both program and project team members. Issues are assigned and have due dates associated with them. Issues are reviewed and tracked at status meetings.
- A change control process was implemented where changes to the baseline plan are approved, deferred, or denied based on pre-defined criteria. This includes procedures for change order creation, change tracking processes, change order criteria, change order analysis, and change escalation procedures.
- Accenture implemented a sign-off procedure for major project deliverables. Subject matter experts sign-off on project phases. The SPP COSMOS project manager has the final sign-off on every phase. Accenture will not receive payment without appropriate sign-offs. The SPP Board of Directors has final acceptance of the project.
- Post-implementation review plans are not formalized. SPP and Accenture plan to have weekly status meetings for two to three months after the system is implemented. If significant issues arise, they will be discussed at the executive level and any necessary changes will be scheduled.
- A document management repository exists that allows for electronic availability of project documentation at SPP and the development sites.

Other significant observations and findings include the following:
• Test plans have been developed for each project phase and are reviewed and approved by the SPP COSMOS project manager prior to moving to subsequent phases. Unit tests, product tests, assembly tests, and simulations are performed when appropriate. Final integration testing will be performed during Market Trials to ensure all systems function properly. A team of member company representatives has been formed to develop test scenarios for the Market Trials.

• Accenture established a training development program. SPP will deliver the training program to internal and external users with support from Accenture and ESCA, the subcontractor developing the Market Operations System. SPP’s website posts the training schedule and requirements. A Customer Readiness Team was formed to track individuals who have attended training and ensure all member companies are represented. Due to FERC’s ruling rejecting SPP’s filing for Regional Transmission Organization (RTO) status, the SPP Board of Directors directed SPP staff to suspend market participant readiness at this time. This includes training plans. Once this is reinitiated, SPP should aggressively pursue their training and customer readiness efforts to ensure member companies are fully trained prior to system implementation.

• The Security Working Group is responsible for disaster recovery planning. A hot back-up site has been designated with a maximum two-hour downtime. Contingency planning is still in the development stage. We are concerned this process is not further along and will continue to monitor the status of disaster recovery and contingency planning.

• Due to an Energy Management System (EMS) upgrade, the Market Operations System timeline slipped four weeks. Accenture, with SPP’s approval, intends to reduce the Market Trial period to account for this slippage and meet the FERC Order 2000 implementation date of January 1, 2002. Should any more slippage occur, we believe Accenture and SPP should not reduce the Market Trial period any further. Further reductions could risk the system not being fully tested by member companies due to time constraints.

• On August 8, 2001, SPP filed a ‘Request for Rehearing’ of FERC’s July 12, 2001 order rejecting SPP’s filing for recognition as an RTO. No rehearing date has been scheduled at this time. The SPP Board of Directors has directed SPP staff to continue to completion the design and build of the COSMOS system, but to suspend market participant readiness at this time.

As stated above, we believe governance and project management procedures over the COSMOS project are adequate to ensure all parties are aware of project issues and concerns and to manage the development and implementation of the system. We will continue to monitor the status of the project as it moves forward.