Southwest Power Pool

TRANSMISSION WORKING GROUP MEETING

August 3-4, 2011

Embassy Suites – Omaha, Nebraska

• Summary of Action Items •

1. Approved the previous meeting minutes as amended.
2. Approved the meeting agenda.
3. Approved a modeling exception to allow the SPS Jones 4 generating unit to be included in the 2011 ITP10 and the 2012 ITPNT models.
4. Approved a motion for SPP to monitor the 60 kV and above system in its TPL analyses and provide potential violations to the Transmission Owners; however, each Transmission Owner will elect whether to provide mitigations for the below 100 kV potential violations.

Southwest Power Pool

Southwest Power Pool

TRANSMISSION WORKING GROUP MEETING

August 3-4, 2011

Embassy Suites – Omaha, Nebraska

• M I N U T E S •

Agenda Item 1 – Administrative Items

TWG Chair, Noman Williams, Sunflower Electric Power Corp., called the meeting to order at 8:03 a.m. The following TWG members were in attendance: (Attachment 1 – Attendance)

Noman Williams, Sunflower Electric Power Corp
Mo Awad, Westar Energy
John Chamberlin, City Utilities of Springfield, On phone
Ronnie Frizzell, Arkansas Electric Cooperative
John Fulton, Southwestern Public Service Company
Joe Fultz, Grand River Dam Authority, On phone
Travis Hyde, Oklahoma Gas and Electric
Dan Lenihan, Omaha Public Power District
Randy Lindstrom, Nebraska Public Power District
Jim McAvoy, Oklahoma Municipal Public Authority
Matt McGee, American Electric Power, On phone
Nathan McNeil, Midwest Energy
Nate Morris, Empire District Electric
Alan Myers, ITC Great Plains
John Payne, Kansas Electric Power Cooperative
Jason Shook, GDS Associates for ETEC
Mike Swearingen, Tri-County Electric Cooperative, On phone
Harold Wyble, Kansas City Power & Light

Travis Hyde, Oklahoma Gas and Electric, made a motion to approve the previous meeting minutes as amended. The motion was seconded by Jim McAvoy and passed unopposed. (Attachments 2a, 2b, 2c – Previous Meeting Minutes)

Alan Myers, ITC Great Plains, moved to approve the meeting agenda, which was seconded by Mo Awad. The motion passed unopposed. (Attachment 3 – Agenda)

It was noted the background materials had been posted in a timely manner. Rachel Hulett, Southwest Power Pool, welcomed the newest members to the TWG: Nate Morris with Empire District Electric and Mike Swearingen with Tri-County Electric Cooperative.

Agenda Item 2 – Review of Past Action Items

Rachel Hulett provided an update on the TWG's current action items (Attachment 4 – Action Items). Mo Awad, Westar Energy, stated action item 1 about Criteria 12 revisions was underway. The task force has an initial draft of changes and will continue to work on the item.

Also the group discussed action item 18, which is about voltage in real-time. A few members noted that their operations personnel need to continue operational studies using a 1.10 p.u. threshold. While other members noted they want a 1.05 p.u. threshold for studies. Rachel reminded the members that SPP Staff is willing to conduct the studies at 1.05 p.u. for a company per special request.

<u>Agenda Item 3 – MOPC/BOD Update</u>

Noman Williams gave an update on the MOPC and Board meetings in July. He described the new processes being developed by SPP staff to monitor changes in project cost estimates as a result of the Project Cost Task Force (PCTF). Noman also discussed the MOPC's concern of SPP not defining projects coming out of the planning studies well enough to create cost estimates as accurately as needed (i.e. necessary reactive compensation requirements). There is a need for SPP to perform reactive compensation studies for projects identified by the ITP studies. As part of this topic, MOPC assigned TWG an action item to revise the ITP manual with more details on reactive and stability studies.

<u>Agenda Item 4 – MDWG Status Report</u>

Scott Rainbolt, American Electric Power, provided a MDWG status update. MDWG had a lengthy discussion on adding an extra model to the 2012 model set based on the year 1 definition of NERC and its application in the soon to be approved TPL-001-2 standard. However, MDWG defined the 2012 model set to be the same structure as the 2011 series and approved the model building schedule.

John Fulton, Southwestern Public Service Company, voiced concern of the stability model building schedule slipping further out each year and members compliance assessments being compressed. He asked why SPP uses a contractor to review the stability models, questioning if members receive enough value for the time and money that the contract requires.

> **Staff to assess the Powertech contract for building stability models and impacts to members and to provide a report back to TWG.**

<u>MITF Update</u>
Kelsey Allen, Southwest Power Pool, discussed the TWG's action item assigned to the Model Improvement Task Force (MITF) on generator Pmax modeled as gross or net. The MITF will continue to discuss this topic and will bring it to MDWG prior to bringing to TWG.

<u>Agenda Item 5 – TWG Reports</u>

<u>Criteria 3.3.3 Benchmarking</u>
Scott Jordan, Southwest Power Pool, shared benchmarking results comparing the winter 2010 peak MDWG model against actual operational data to meet Criteria 3.3.3 (Attachment 5 – 3.3.3).

<u>TWG Work Schedule</u>
Rachel Hulett provided an update of 2011 planning activities shown in the TWG work schedule (Attachment 6 – TWG Work Schedule). Noman Williams requested the draft 2011 ITP report(s) be brought to the TWG for review before being presented to the MOPC.

<u>Agenda Item 6 – 2011 ITP Activities</u>

<u>ITP10</u>
Bob Lux, Southwest Power Pool, updated the group on the 2011 ITP10 studies. SPP has done initial analysis and provided potential violations at the July summit. Staff seeks member feedback by Friday, August 5. TWG discussed the analyses.

ITPNT

Rachel Hulett gave an update on the status of the 2011 ITPNT. Staff will finish evaluation of the potential issues and develop solutions by the end of August. Staff will review the solutions with stakeholders in September.

John Fulton requested the Jones 4 unit be included in the ITP models— more specifically to include it in the 2011 ITP10 and NT models, noting it may be too late to include in the 2011 ITPNT models. Staff agreed it was too late to include in the 2011 Near-Term Assessment. This modeling request was identified as special TWG review per the ITP manual since it didn't meet several requirements, including having a Definitive Interconnection System Impact Study. John Fulton and Joe Taylor explained the unit is being planned for an in-service date of summer 2013 with other details as follows:

- o Expenditures have been spent on the unit
- o Unit has been studied in the 2010 AGP1 transmission service study
- o SPS plans to submit the unit in the next SPP generation interconnection cluster
- o SPS had filed for a CCN and environmental permitting for the unit.

John Fulton made a motion to include the SPS Jones 4 generating unit to be included in the 2011 ITP10 and 2011 ITPNT models, if possible (otherwise 2012 ITPNT models). The motion was approved unanimously, which was seconded by Travis Hyde.

Agenda Item 7 – Reactive Studies Update

Doug Bowman, Southwest Power Pool, gave a presentation on the ongoing reactive compensation studies (Attachment 7 - Voltage Stability). One concern voiced was the analysis might not identify all voltage collapses since the base case contained a number of high voltages.

Agenda Item 8 – Stability Update

Scott Jordan presented an update on 2011 transient stability study work at SPP (Attachment 8 - Transient Stability). He shared the methods SPP used to benchmark the DSA tools against the PSS/E tool for stability analyses. Randy Lindstrom asked for plot simulation comparisons as part of the benchmarking, and the group noted that Brown's Ferry should be used as the reference bus instead of Sooner.

Scott also shared SPP's proposed transient stability criteria, which is required in TPL-001-2. The group discussed the criteria and asked for graphs of the waveform of the damping curve and recovery time between 0-20 seconds. They suggested renaming the term "transient voltage recovery" to "transient voltage threshold". Also the group noted there will need to be a staging component for the criteria's effective date. TWG formed a task force to further develop the transient voltage criteria, consisting of a NPPD representative, an SPS representative, Joe Fultz (GRDA), and Al Tamimi (Sunflower). After the meeting, SPS appointed Rene Miranda to the task force, NPPD appointed Brian Brownlow to the task force, and Westar volunteered Don Taylor for the task force.

For the 2011 TPL stability analysis, Scott will provide a list of the past studies NERC Category "B", "C", and "D" events to the members for comment. Members will also be requested to provide any additional events to Scott.

Agenda Item 9 – EIPC Update

Doug Bowman shared the Eastern Interconnection Planning Collaborative (EIPC) efforts (Attachment 9 – EIPC Update). Currently the EIPC is performing macroeconomic analysis of 72 various future scenarios. By the end of the year, the EIPC will define three scenarios to be used in determining transmission plans for the future. Doug will continue to update TWG on the EIPC's progress.

Southwest Power Pool

Agenda Item 10 – DC Interconnections Update

Doug Bowman provided an update on the three high voltage DC interconnections, the Tres Amigas and two Clean Line projects. Staff has worked with the interconnecting entities to determine the scope of work, and the entities are now performing the studies.

Agenda Item 11 – Special Protection System – Ensign Wind Farm

Madan Gaudi, NextEra Energy Resources, presented his Automatic Control System and Special Protection System (SPS) planned for NextEra Energy Resources' Ensign Wind Farm (Attachment 10a, 10b – Ensign SPS). TWG discussed the SPS and asked NextEra several questions.

TWG asked NextEra to provide them with "All applicable studies supporting the design requirements of the SPS" per Criteria 7.4.7 so they could properly review the SPSs conformance to SPP requirements and NERC Standards. Also TWG requested an additional study be performed to determine interaction between nearby SPSs, ensuring reliability of the system is not compromised. TWG identified the nearby Flat Ridge SPS.

TWG noted a deficiency of the SPS -- part of the scheme was designed to begin an operational function when at 105% of emergency rating (rate B) -- as this is a direct violation of the SPP Criteria, the SPS should not allow the system to overload past the emergency rating.

> **Staff will work with NextEra to provide study information to TWG on the Ensign Wind Farm special protection scheme.**

A member suggested a paper be created listing working group expectations and outlining a process for how proposed special protection schemes should be presented to the various working groups and what materials should be required.

> **TWG to discuss creating a process to include all the requirements when proposing Special Protection Schemes**

Agenda Item 12 – RE, TPL Standards

RE's 2010 TPL Report Finding

Jason Speer, Southwest Power Pool, gave a presentation on the 2010 TPL report findings (Attachment 11 – 2010 TPL Review). He made several recommendations on how the TPL study process could be changed going forward, including, 1) changing the voltage levels monitored in the study 2) having members review OPM mitigations, and 3) creating a master TPL report. Noman asked staff to draft a response to the RE finding letter.

> **Staff to draft a response to the RE's 2010 TPL findings letter and provide to TWG for feedback.**

The first recommendation was changing the voltage levels SPP monitors from 60 kV and above to 100 kV and above. This recommendation was based on reducing the large number of potential violations occurring from these 60 kV contingencies. There was lengthy discussion on this item. Several entities believed SPP should require mitigations on all 60 kV and above systems. Others acknowledged the 69 kV issues, but were concerned with the large number of issues on their systems and the resource limitations to determine mitigations.

The second recommendation was having the members review their OPM mitigations. As SPP monitors a large number of facilities, OPM develops mitigations plans for many potential violations. Staff currently implements this recommendation. Several members noted the RE's concerns that OPM may create unrealistic mitigations were valid. There were two suggestions: limit the number of steps of OPM created mitigations prior to dropping load; limit machine movements on the system. The members asked for more time to review the possible mitigation measures available in the OPM tool.

> **Dan Lenihan made a motion for SPP to monitor the 60 kV and above system in its TPL analyses and provide potential violations to the Transmission Owners; however, each Transmission Owner will elect whether to provide mitigations for the below 100 kV potential violations. Mo Awad seconded the motion. The motion passed with 9 votes for, 3 votes against (Arkansas Electric Cooperative, Empire District Electric, and East Texas Cooperatives) and 5 abstentions. Ronnie Frizzell, Arkansas Electric Cooperative, opposed stating the SPP system needs to be adequately studied to keep the lights on, and the ITP studies do not have the depth or breadth of the TPL assessment.**

The third recommendation was creating a master TPL report with each company's assessment included in the SPP report. The members discussed this option but could not agree.

TPL-001-2 Update
Rachel Hulett reviewed staff's gap analysis of the new TPL-001-2 standard (Attachment 12 – TPL Gap Analysis). Members were encouraged to review the analysis further before the next meeting when staff could address any questions.

Agenda Item 13 – FAC-010, Planning SOLs Update

Jason Speer stated SPP staff is identifying planning SOLs and IROLS in 2011 as required in NERC Standard FAC-010 and SPP Criteria 12.3.2. Staff will use its 2011 TPL analysis output as a starting point for identifying SOLs/IROLs. Results will be brought back to TWG later this year.

Jason asked the group to interpret a sentence in Criteria that states, "unless there are studies or system knowledge that the SOL is not an IROL." TWG determined this was meant to be the use of engineering judgment.

Agenda Item 14 – RE, 2011 Probabilistic Assessments

Michael Odom, Southwest Power Pool, presented probabilistic assessments SPP is performing in 2011 (Attachment 13 – Probabilistic Assessment). There were no questions on the assessments.

Agenda Item 15 – Reliability Standards Development Introduction

Jonathan Hayes, Southwest Power Pool, introduced himself to the group and explained his role in the SPP organization, which is to help develop the reliability standards (Attachment 14 – Reliability Standards Update). This should help provide the members value. SPP is working actively to get member feedback and input in the standard development process.

Agenda Item 16 – Project Cost Task Force – Cost Estimating

Terri Gallup, American Electric Power, shared a presentation on the PCTF work and cost estimation process developed by the group (Attachment 15a, 15b – PCTF). The new cost estimation process will include things like new levels of cost estimates, a standardized cost estimation template (SCERT), and the new Conditional Notifications to Construct (CNTC). The MOPC created the new Project Cost Working Group (PCWG), who will review cost variances on projects, as part of this effort. Terri noted the new processes are only applicable to future projects. The quarterly project tracking process will continue as well. TWG was encouraged to read the PCTF whitepaper and PCWG charter.

John Fulton asked how much time would be given to supply +/- 30% study estimates, stressing the importance of realistic timeframes to provide study estimates. Terri responded the whitepaper requires estimates be submitted four months prior to Board approval. John noted this may cause a disconnect in the process as new projects may need to be identified in the last four months of a study. Staff noted it will finalize the SCERT in the coming weeks and provide it to TWG for the 2011 ITP10 and NT studies.

Agenda Item 17 – Study Estimate Design Guide (DBPPCTF)

Jake Langthorn, Oklahoma Gas & Electric, walked through the approved Study Estimate Design Guide developed by the Design Best Practices and Performance Criteria Task Force (DBPPCTF). There was discussion on the paper, and an amendment was made to the cost estimation section of the paper (Attachment 16 – Study Estimate Design Guide). Noman noted this design guide may be partially owned by TWG in the future, but it has been given to PCWG at this time.

Agenda Item 18 – Interconnection Updates

There were no updates. All outstanding interconnection reviews have been approved.

Agenda Item 19 – Others

NERC Planning Committee Update
Noman Williams presented a NERC Planning Committee Update (Attachment 17 – NERC PC Mtg).

Seams Cost Allocation Update
Noman Williams mentioned the new FERC Order 1000 was released that will require the inter-regional planning and cost allocation, remove Right of First Refusal, and possibly revise planning requirements.

Novations
Rachel Hulett informed the group two novations had been accepted by FERC in June: the Priority Project V-plan novations to Prairie Wind Transmission and ITC Great Plains. NTCs were issued the novated parties. SPP also issued its first generation interconnection NTCs in August.

Agenda Item 20 – Closing Administrative Duties

Rachel Hulett summarized the action items from the meeting:

- Staff to assess Powertech contract and impacts to members for building stability models and provide a report to TWG.
- Staff will work with NextEra to provide study information to TWG on the Ensign Wind Farm special protection scheme.
- TWG to discuss creating a process to include all the requirements when proposing Special Protection Schemes
- Staff to draft a response to the RE's 2010 TPL findings letter and provide to TWG for feedback.

Noman Williams asked the group for future meeting topics, and received two suggestions: education on the markets and update on Seams Steering Committee activities. The next face-to-face meeting will be November 2-3, 2011 in Oklahoma City.

Randy Lindstrom moved to adjourn the meeting. Motion was passed unopposed.

The meeting was adjourned at 11:05 a.m.

Respectfully Submitted,

Rachel Hulett
Secretary

Southwest Power Pool

Southwest Power Pool, Inc.

TRANSMISSION WORKING GROUP MEETING

August 3 & 4, 2011

Embassy Suites Omaha/Omaha, NE

• ATTENDANCE LIST •

Name	Company
Robby Michiels	Cleco
Matt Bordelon	Cleco
Roy Boyer	Xcel Energy
John Fulton	SPS/Xcel Energy
Mo Awad	Westar Energy
Jim McAvoy	OMPA
NATE MORRIS	EDE
Julie Denton	Independence P&L (INDN)
Travis Hyde	OG+E
Noman Williams	Sunflower
Scott Rainbolt	AEP
Jonathan Hayes	Southwest Power Pool
Kelsey Allen	Southwest Power Pool
Paul Simoneaux	Entergy
Rob LAMNECK	NEXANS (Valley Group)
Rachel Hulett	SPP
William Mauldin	SPP
Joe Taylor	Xcel Energy

Southwest Power Pool

Southwest Power Pool, Inc.

TRANSMISSION WORKING GROUP MEETING

August 3 & 4, 2011

Embassy Suites Omaha/Omaha, NE

• ATTENDANCE LIST •

Name	Company
HAROLD WYBLE	KCP&L
Alan Myers	ITC Great Plains
RANDY LINDSTROM	NPPD
Dan Lenihan	OPPD
John Payne	KEPCo
Ronnie Frizzell	AECC
JASON SHOOK	GDS/ETEC
AL Tamimi	SEPC
JASON ATWOOD	VENTYX
Scott Feuerborn	Burns & McDonnell
MARY ANN MOORE	NPPD INTERN (NSA)
Dustin Betz	NPPD
Madan Gaudi	NextEra Energy Resources
Nathan McNeil	MIDW

Southwest Power Pool

Southwest Power Pool, Inc.

TRANSMISSION WORKING GROUP MEETING

August 3 & 4, 2011

Embassy Suites Omaha/Omaha, NE

• ATTENDANCE LIST •

On-Phone

Name	Company
Matt McGee	AEP
Deepthi Kasinaduni	GRDA
Joe Fultz	GRDA
Syed Ahmad	FERC
Tony Gott	AECI
Mike Swearingen	Tri-County Electric
John Chamberlin	CU
John Allen	CU
Scott Jordan	SPP
Bob Lux	SPP
Michael Odom	SPP
Wayne Galli	Clean Line
Jason Speer	SPP
Jake Langthorn	OG+E
Terri Gallup	AEP
John Mills	SPP
David Kelley	SPP

Southwest Power Pool

TRANSMISSION WORKING GROUP MEETING

May 11-12, 2011

Hyatt Regency – Tulsa, Oklahoma

• Summary of Action Items •

1. Approved the March 1, 2011 meeting minutes.
2. Approved the March 25, 2011 meeting minutes
3. Approved the meeting agenda.
4. Approved the 2011 MRSWS Summer Report.
5. Approved the addition of identified permanent flowgates.
6. Approved the elimination of identified permanent flowgates.
7. Approved recognition of Sam McGarrah for his input and contributions to TWG.
8. Approved SPP Criteria 12 and 3 revisions.
9. Approved that TWG does not support the proposed SPS policy; furthermore, if changes need to made to the application of SPS's, TWG recommends the revisions be made to SPP Criteria 7.4 'Special Protection Systems Equipment'.
10. Approved the elimination of an OGE requested flowgate.

Southwest Power Pool

TRANSMISSION WORKING GROUP MEETING

May 11-12, 2011

Hyatt Regency – Tulsa, Oklahoma

• M I N U T E S •

Agenda Item 1 – Administrative Items

TWG Chair Noman Williams called the meeting to order at 8:03 a.m. on Wednesday, May 11. The following members were in attendance or represented by proxy: (Attachment 1 – Proxies) (Attachment 2 – Attendance)

Noman Williams, Sunflower Electric Power Corp
Mo Awad, Westar Energy
John Chamberlin, City Utilities of Springfield
Jason Fortik, Lincoln Electric System
Ronnie Frizzell, Arkansas Electric Cooperative
Ed Horgan for John Fulton, Southwestern Public Service Company
Joe Fultz, Grand River Dam Authority
Travis Hyde, Oklahoma Gas and Electric
Dan Lenihan, Omaha Public Power District, On phone
Randy Lindstrom, Nebraska Public Power District
Jim McAvoy, Oklahoma Municipal Public Authority
Sam McGarrah, Empire Electric District
Matt McGee, American Electric Power
Nathan McNeil, Midwest Energy, On phone
Alan Myers, ITC Great Plains, On phone
John Payne, Kansas Electric Power Cooperative
Jason Shook, GDS Associates for ETEC
Mitch Williams, Western Farmers Electric Cooperative, On phone
Brian Wilson for Harold Wyble, Kansas City Power & Light

Jim McAvoy motioned to approve the March 1-2, 2011 meeting minutes. The motion was seconded by Jason Fortik and approved unanimously. (Attachment 3a – March 1-2 minutes)

Mo Awad motioned and Jason Shook seconded the motion to approve the March 25, 2011 minutes. The motion passed unopposed. (Attachment 3b – March 25 minutes)

Jason Shook motioned to approve the meeting agenda, which Jason Fortik seconded. The motion passed unopposed. (Attachment 4 – Agenda)

Meeting materials were noted as posted on-time.

Agenda Item 2 – Review of Past Action Items

Rachel Hulett, SPP, went through statuses of TWG's current action items (Attachment 5 – Action Items). Mo Awad, Westar Energy, stated that item 1 is still in progress and will be done for the next meeting. There were no questions on the action items.

Agenda Item 3 – MOPC/BOD Update

Noman Williams provided a MOPC/BOD update. MOPC accepted the Area Generation Connection Task Force's whitepaper but noted the hub concept needs additional vetting. MOPC approved the two 2011 ITP10 futures. Also MOPC is looking for an update on the Wind Integration Task Force (WITF) action items assigned to each working group. TWG reviewed their related WITF action items.

Agenda Item 4 – TWG Reports

2011 MRSwS Summer Report
Rachel Hulett summarized the 2011 MRSWS Summer Report (Attachment 6 – MRSwS report). Matt McGee, American Electric Power, stated there were several projects in Entergy not included in the model and there was also a model error where an SPP line was removed. Matt could not affirm if the modeling error impacted the study results.

> **Ronnie Frizzell motioned to approve the 2011 MRSwS Summer Report. Jim McAvoy seconded the motion. The motion was approved with AEP opposing due to modeling inaccuracies.**

2011 Work Schedule
Rachel Hulett updated the group on TWG and modeling activities through the next quarter (Attachment 7 – TWG work schedule). Ed Horgan, Southwestern Public Service Company, asked for an update on the 2011 dynamic models, as SPS needs the models by early June. Noman Williams voiced members' need to obtain MDWG models sooner.

UVLS Update
Rachel Hulett informed the group SPP will not perform a UVLS study. SPP is not required to perform the assessment. As there is only one UVLS scheme in SPP, which is owned by AEP, AEP will be responsible for studying its UVLS protection system.

Agenda Item 5 – MDWG Status Report

Scott Rainbolt, MDWG Chair, provided a MDWG status update and discussed MDWG's action item- to address Pmax and operating reserve issues (Attachment 8 – MDWG reserve planning). MDWG recommended using the MITF white paper for Pmax concerns– allow modeling generation at gross or net capability. The group discussed the issue and decided MITF should re-evaluate the net and gross generation requirements for stability concerns.

> **AI: MITF to address how to model generation, either net or gross, in order to more accurately assess system stability.**

MDWG remanded the policy issue of modeling operating reserves back to TWG. Scott shared MDWG's two options: 1) Operating reserves are met in SPP models-- a) using fake transactions, or b) with fictitious generation; 2) Operating reserves are not met in the SPP models. MDWG does not favor the options. The group discussed the options of whether operating reserves should be modeled. A straw poll was taken to determine if the members were in favor of option 1 or 2. The group was split 3 for option 1, 9 for option 2, and 3 indeterminate.

Agenda Item 6 – Annual Flowgate/TRM Review

The marketers were asked to leave the room for this market sensitive item.

Flowgate Assessment

John Langford, SPP staff, reviewed the process of the annual flowgate assessment and presented the list of candidates for addition and elimination. The group reviewed the candidates for addition. Dan Lenihan, Omaha Public Power District, asked SPP to write a formal assessment document for the Transmission Planners to use for compliance purposes.

A motion to approve inclusion of 5 flowgates as permanent flowgates was made by Randy Lindstrom and seconded by Joe Fultz. The motion was approved unanimously.

The group reviewed the candidates for removal.

Mo Awad motioned to approve removal of 41 flowgates from the list. The motion passed unopposed, which was seconded by Sam McGarrah.

AI: Staff to create report(s) of 2011 Flowgate Assessment and 2011 TRM Assessment by May 20.

TRM Assessment

Rachel Hulett shared the TRM results with the group. Staff incorporated TOs comments into the list, but TWG asked for an additional day to review the list. The vote was moved to Thursday.

Rachel Hulett noted staff's annual review of ATC was considered complete for 2011 based on staff's and TWG's review of governing documents to address the April 1, 2011 enforceable MOD standards. There were no objections.

Agenda Item 7 – 2011 Integrated Transmission Planning (ITP) Activities

2011 ITP10 – Modeling DC to AC conversion

Bob Lux, SPP staff, gave a presentation on process of a DC to AC conversion to create the ITP10 AC models (Attachment 9 – AC model). Bob reported the Future 1 summer peak model will be available in the next week for TWG review. Staff will ask TWG to review the model in a one week timeline.

2011 ITP10 – ITP Manual Review

Rachel Hulett gave a brief overview of the ITP manual focusing on the newly written ITP10 section (Attachment 10 – ITP manual). The group made several edits to the manual. Noman Williams requested TWG have all comments to staff by the end of May in preparation for additional review in June. The ITP manual will go to MOPC in July for finalization.

Rachel also shared the upcoming 2011 ITP10 activities for TWG. In addition to the review of AC model and ITP manual this month, TWG will be reviewing the constraint assessment. In early July, staff should be providing the ITP10 potential violations to the stakeholders for feedback and development of solutions. A summit will be held on July 21.

2011 ITPNT

Rachel Hulett provided a 2011 ITPNT update. Staff modified the models to resolve outstanding issues and re-ran the AC analysis. She noted an additional 42 MW unit in New Mexico was included in the models.

Agenda Item 8 – Reactive Study Progress Report

Doug Bowman, SPP Staff, presented an update on the reactive study (Attachment 11 – Reactive Study report). Staff has updated the Reactive study scope to include member comments, and staff is refining the scope to limit analysis in 2011 to the available resources. As part of this year's study, staff will perform a load pocket analysis. Doug shared existing and proposed load pockets for study and asked the group to prioritize the load pockets. The group discussed the prioritization, but asked staff to initially rank them and provide that information to TWG. Once Doug has provided the ranking, TWG will provide comments by May 20.

> **AI: Staff to rank the load pockets for the reactive study and ask for member feedback by May 20.**

Agenda Item 9 – Criteria 3.5 Review

Keith Tynes, SPP staff, presented an update on action item 6, concerning SPP Criteria 3.5 (Attachment 12 – Criteria 3.5 Staff Impacts). Staff suggested the TOs perform the short circuit analysis for new projects in coordination with SPP, since TOs have the data and knowledge of their local systems. In relation to stability and reactive compensation, staff suggested SPP address these issues in the ITP, noting staff would need at least 12-36 months to become skilled at comprehensive reactive analyses. The group reviewed the proposal and agreed short circuit data should be required when proposing a new project so short circuit analysis can be performed.

Staff is working to address cost estimate impacts if an NTC is issued for a project prior to these studies. TWG agreed to Keith's proposal that staff create an implementation plan to address the short circuit, stability, and reactive needs in the ITP.

> **AI: Staff to develop a strawman framework for enhancing the ITP planning process which will phase in coordinated levels of reactive compensation and short circuit analysis for better project cost estimation.**

Katherine Prewitt, SPP staff, noted the Design Best Practices and Performance Criteria Task Force may tackle this through new standards.

Agenda Item 10 – RE, TPL Compliance Interpretation

RE

Greg Sorenson, SPP RE, explained the RE's interpretation on TPL standards, the RE's review of SPP's 2010 TPL assessments, and future standard impacts (Attachment 13 – 2010 TPL Assessment review). There were several questions from the group, and Noman Williams voiced concern the interpretation leads to duplicative efforts, defeating SPP's collaborative planning purposes. Greg noted the SPP assessment is not comprehensive for compliance purposes. SPP's analysis and identification of voltage and current violations is comprehensive and covers N-1 and N-2 cases, but the assessment is missing links between the voltage and current problems identified by the study and the necessary construction plans, operating guides and other mitigations. The SPP report also lacks details about each individual Transmission Planner's system, potential violations, generation plans, consideration of stability, etc. The SPP RE will be publishing its report on May 31, 2011 and Transmission Planner assessments should be completed for the 2010 study year by that time.

MOPC Response

Noman Williams explained the Board Chairman asked him to write a white paper on SPP's regional efforts in place of individual efforts to meet compliance for several standards—TOP, TPL, and MOD standards (Attachment 14 – MOPC Action Item). Noman solicited comments from the members.

Randy Lindstrom, Nebraska Public Power District, suggested we form a working group or task force that works on creating the detailed TPL assessments, which is similar to MAPP's process, to meet compliance requirements. The group discussed if SPP's assessments should be more comprehensive and how to make them comprehensive. A member asked if SPP could incorporate and report on TLR and EEA events as part of this effort. In a straw poll, roughly 1/3 of the members have performed their individual compliance studies in the past, and the other 2/3 of members have relied upon SPP's studies in the past. TWG will review this item further and consider forming a task force to enhance the SPP assessments.

AI: TWG to consider a task force to enhance the TPL assessments.

Agenda Item 11 – Business Practice Reviews (BPRs)

Katherine Prewitt presented BPR-021 ATP business practice (Attachment 15a – ATP presentation). Business Practice Working Group is currently reviewing this BPR and will take the practice to MOPC for approval at its July meeting. Staff asked for TWG comments pertaining to any reliability impacts due to this practice, and made several edits to the business practice (Attachment 15b – ATP BPR-021). TWG comments are due by the end of May.

Agenda Item 13 – EMTP Study for Woodward-Tuco 345 kV project

Travis Hyde, Oklahoma Gas and Electric, introduced staff from Mitsubishi Electric Power Products Inc. Mitsubishi staff presented the study results for the Woodward-Tuco 345 kV line transients and over-voltage mitigation (Attachment 16 – EMTP presentation). Group appreciated the information sharing and suggested that it is a good approach to perform this type of simulation in planning long AC transmission lines. The group also considered costs of reactive support needed on EHV facilities to take into account in cost estimation phase of projects.

On Thursday morning, Noman announced this was the last TWG meeting for Sam McGarrah, Empire District Electric. Noman thanked Sam for his hard work since 2001 and gave him best wishes in future endeavors.

Ronnie Frizzell motioned to recognize Sam McGarrah for his input and contributions to TWG. The motion passed unopposed, which was seconded by Jason Fortik.

Agenda Item 12 – Nebraska City-Sibley project review

Keith Tynes shared the Nebraska City-Sibley Priority Project was re-examined per direction of SPP Board to evaluate the impact of the project on members should OPPD exit SPP (Attachment 17 – Neb City presentation). Staff evaluated several transmission options as alternatives to this Priority Project, and the main focus of evaluation was cost effectiveness, financial and operational benefit as well as market impact. Randy Lindstrom voiced concern that the re-conductor option could pose major reliability and congestion issues. Randy also disagreed with the conclusions in the presentation.

Staff will continue to work with the members in evaluation of the alternatives. Staff will first share results with KCPL, OPPD, NPPD, LES, AECI, and Westar, and then ask TWG to review the results and provide feedback by mid-June in preparation for July MOPC meeting.

Agenda Item 14 – SPP Criteria

Criteria 3

Rachel Hulett explained the Criteria 3 Task Force and later TWG agreed to set the upper voltage limit to 1.05 pu for contingency conditions. System elements cannot normally operate above 1.05 pu. Randy Lindstrom voiced concern of meeting a 1.05 pu requirement since he's been underneath MAPP with a 1.10 pu requirement. There was a lengthy discussion around the +5% voltage criteria, and the group came to the conclusion that SPP does not need to change the Criteria based the following: With MAPP's limit of 1.10 pu, MAPP requires TOs to be below 1.05 pu in 30 minutes, and they also require mitigations for N-1 contingencies above 1.05 pu; with SPP's limit of 1.05 pu, SPP requires mitigations for long-term planning purposes, not 30-minute intervals (i.e. the 30-minute interval is seen as an operations only requirement, not a planning requirement).

> **AI: Ask ORWG to provide clarification in Criteria 5.2.4.1d that "post-contingent bus voltages in excess of +/- 10%" should be the 30-minute allowance.**

Criteria 12
Rachel Hulett explained several references were wrong in SPP Criteria 12 and Criteria 3 (Attachment 18 – Criteria 12 revisions). Staff proposed revisions to correct this. Ed Horgan noted that other items like conductor temperature ratings in Criteria 12 were incorrect. Ed Horgan and Hassan Shah, SPP staff, volunteered to help Mo Awad on an existing action item to clean-up Criteria 12.

> **A motion to approve SPP Criteria 12 and 3 revisions was made by Mo Awad and seconded by Jason Shook. The motion was approved unanimously.**

Agenda Item 15 – Special Protection Scheme Policy

Charles Hendrix reviewed the latest SPS policy with the group. The group discussed the policy and provided revisions (Attachment 19 – SPS policy). After much discussion, several members voiced concern that the policy was not good for SPP, and TWG agreed they did not support the policy from a reliability perspective.

> **Sam McGarrah motioned that TWG does not support the proposed SPS policy for the reasons below; furthermore, if changes need to made to the application of SPS's, TWG recommends the revisions be made to SPP Criteria 7.4 'Special Protection Systems Equipment'. The motion was seconded by Randy Lindstrom, and was approved unanimously.**

Reasons:

- o Potential violation of NERC Standards
- o This proposed policy is not necessary because it's covered under SPP Criteria 7.4.
- o Criteria 7.4 has been successfully used in previous situations.
- o This proposed policy establishes a normal practice, rather than an exception
- o SPS's should not be used for N-1 situations to avoid instability and cascading outages
  - ▪ Use of SPS's to alleviate thermal overloads may be acceptable upon sufficient review
- o Unintended consequences of interactions between SPS's are unknown and may be detrimental to reliability of the system
  - ▪ Loosing multiple generators with SPS's in the same vicinity could result in system problems
- o If there are needed changes for the application of SPS's, then Criteria 7.4 should be revised to reflect those changes

Agenda Item 16 – Interconnection Updates

OGE/WFEC Washita-Gracemont
Charles Hendrix updated the group on OGE/WFEC Washita-Gracemont 138 kV interconnection. Charles noted that short-circuit analysis has not been performed. Matt McGee asked staff to perform an additional stability analysis, and Charles agreed to perform the analyses.

Midwest/Sunflower Heizer-Mullergren
Al Tamimi, Sunflower Electric, stated the Heizer-Mullergren interconnection review with affected parties was complete. TWG vote on the interconnection will be soon.

Clean Line and Tres Amigas
Noman Williams stated the Clean Line and Tres Amigas interconnections studies were underway.

Agenda Item 17 – Others

NERC Planning Committee Update
Noman Williams updated the group on NERC Planning Committee activities (Attachment 20 – NERC PC). He will provide these updates as background materials in the future.

TRM
No additional feedback was provided on TRM values. Since everyone was not present to vote on the TRM values, staff will send an email vote on approval of TRMs due by Friday May 13.

Travis Hyde stated a flowgate that was approved Wednesday for addition to the flowgate list now needed to be removed.

> **Travis Hyde motioned to remove OGE's requested flowgate from the list. Motion passed unopposed, which was seconded by Joe Fultz.**

OATT Attachment C Compliance Filing
Rachel Hulett informed the group about changes made to SPP Tariff Attachment C due to FERC comments (Attachment 21 – Attachment C compliance filing). The changes expand the flowgate addition/deletion procedure for clarity.

Agenda Item 18 – Closing Administrative Duties

The next meeting is August 3-4 in Omaha, Nebraska. Rachel summarized the meeting action items:

- MITF to address how to model generation, either net or gross, in order to more accurately assess system stability.
- Staff to create report(s) of 2011 Flowgate Assessment and 2011 TRM Assessment by May 20.
- Staff to rank the load pockets for the reactive study and ask for member feedback by May 20.
- Staff to develop a strawman framework for enhancing the ITP planning process which will phase in coordinated levels of reactive compensation and short circuit analysis for better project cost estimation.
- TWG to consider a task force to enhance the TPL assessments.
- Ask ORWG to provide clarification in Criteria 5.2.4.1d that "post-contingent bus voltages in excess of +/- 10%" should be the 30-minute allowance.

Sam McGarrah, seconded by Travis Hyde, motioned to adjourn the meeting. The meeting was adjourned Thursday at 11:54 a.m.

Respectfully Submitted,

Rachel Hulett
Secretary

Supplemental Activity

TRM Assessment

From May 12, 2011 to May 14, 2011, TWG voted via email on the 2011 TRM Assessment values that were discussed in the TWG meeting.

> **TWG to approve the 2011 TRM values calculated and posted on TrueShare. The motion was approved with 18 votes in favor and 0 in opposition. Note that AEP asked for one correction to a value, which was accepted.**

Interconnection Reviews

In late June, two interconnections were provided to TWG for review: OGE/WFEC Gracemont-Washita 138 kV ckt 2 interconnection and MIDW/MKEC Heizer-Mullergren 115 kV interconnection. After comments were addressed, TWG members voted via email on the following two motions during the week of July 11, 2011:

> **TWG approves the Gracemont-Washita interconnection has been through sufficient review and there are no outstanding issues. The motion passed with 16 votes in favor and 0 in opposition.**

> **TWG approves the Heizer-Mullgren interconnection has been through sufficient review and there are no outstanding issues. The motion passed with 16 votes in favor and 0 in opposition.**

Southwest Power Pool

TRANSMISSION WORKING GROUP

June 9, 2011

Webconference

• M I N U T E S •

Agenda Item 1 – Administrative Items

The meeting was called to order at 10:00 a.m. The following members were in attendance or represented by proxy: (Attachment 1 – Proxies)

TWG Members

John Chamberlin, City Utilities of Springfield
Ronnie Frizzell, Arkansas Electric Cooperative
John Fulton, Southwestern Public Service Company
Joe Fultz, Grand River Dam Authority
John Mayhan for Dan Lenihan, Omaha Public Power District
Randy Lindstrom, Nebraska Public Power District
Mark Loveless for Jim McAvoy, Oklahoma Municipal Public Authority
Nathan McNeil, Midwest Energy
Matt McGee, American Electric Power
John Payne, Kansas Electric Power Cooperative
Jason Shook, GDS Associates for ETEC
Mitch Williams, Western Farmers Electric Cooperative
Harold Wyble, Kansas City Power & Light

Other Stakeholders and Staff

Paul Arnold, Power Engineers
Roy Boyer, Southwestern Public Service Company
Derek Brown, Westar Enregy
Bruce Cude, Southwestern Public Service Company
Ricardo Galarza, PSM Consulting
Tony Gott, Associated Electric Cooperative
Dan Hartman
Rachel Hulett, SPP Staff
Deepthi Kasinaduni, Grand River Dam Authority
Lloyd Kolb, Golden Spread Electric Cooperative
Jim Krajecki, Customized Energy Solutions
Jake Langthorn, Oklahoma Gas and Electric
Tim Miller, SPP Staff
Nate Morris, Empire District Electric
Harshikesh Panchal, Constellation Energy
Ronda Redden, Oklahoma Gas and Electric
Josh Ross, SPP Staff

Agenda Item 2 – 2011 ITP10 Constraint Review

Josh Ross, SPP Staff, explained the ITP10 constraint review. Since the economic model can only use constraints to dispatch around, this identification of constraints is an important step in the economic assessment. SPP staff began the list with the NERC Book of flowgates and the latest TWG review of flowgates.

Several questions arose about new constraints being applied that might impact the results. Staff responded that any new proposed constraints would be evaluated by staff to determine if they warrant inclusion in the ITP10 constraint list. A question came up regarding the need for some of the constraints that would most likely go away by 2022 due to transmission upgrades that are currently being built. Staff responded that the OTDF constraints of this nature would not cause any congestion, as these constraints would not bind and would thus have zero impact on the economic dispatch. The PTDF constraints of this nature are being evaluated by SPP Staff to determine if they should be removed from the constraint list.

Staff noted that the constraints will be used in the economic analysis to determine congestion. Based on the congestion, staff and the members will have to determine if they should create a constraint to dispatch around the congestion or develop a transmission solution to resolve the congestion. This will be a crucial part of the assessment.

Staff has received member feedback, changing constraints or ratings. Staff asked TWG to provide any additional comments to staff by Friday, June 10.

Agenda Item 3 – ITP Draft Manual Review

Rachel Hulett, SPP Staff, asked the TWG for comments on the ITP10 portion of the draft ITP manual. A few comments were made in the meeting (Attachment 2 – ITP Manual). Rachel asked the group to provide comments prior to the next call. The TWG will be asked to endorse the manual at the next conference call.

Agenda Item 4 – Update on Criteria 5 Action Item

Rachel Hulett informed the TWG of progress on the Criteria 5 action item assigned to ORWG to revise the Criteria to reflect a high voltage maximum limit of 1.05 pu for operational studies ("Ask ORWG to provide clarification in Criteria 5.2.4.1d that "post-contingent bus voltages in excess of +/- 10%" should be the 30-minute allowance"). SPP Operations relayed this message: ORWG does not want to change the limits for the following reasons: the next day studies use the MDWG models as the starting point for analysis, and the MDWG models have high voltage problems present; this will require more interaction with the operators and they didn't want to supply mitigations for problems starting at 1.05 pu. SPP Operations is willing to change an area's next day study limits to 1.05. Please contact Jason Smith to change. TWG discussed this and took away an action item to talk to their operations folks to verify they're operating system at 1.05 pu and why they do not want to change the next day studies limits.

> **AI: Members talk to their respective operators to understand and determine if operational studies should use a maximum 1.05 pu voltage limit.**

Agenda Item 5 – Closing

The next meeting was scheduled for June 22, 2011 from 10-12 p.m. The meeting was adjourned at 11:15 a.m.

Respectfully Submitted,

Rachel Hulett
TWG Secretary

Southwest Power Pool

TRANSMISSION WORKING GROUP

June 22, 2011

Webconference

• M I N U T E S •

Agenda Item 1 – Administrative Items

TWG Chair Noman Williams called the meeting to order at 10:02 a.m. The following members were in attendance:

TWG Members

Noman Williams, Sunflower Electric Power Corp
Mo Awad, Westar Energy
John Chamberlin, City Utilities of Springfield
Ronnie Frizzell, Arkansas Electric Cooperative
John Fulton, Southwestern Public Service Company
Joe Fultz, Grand River Dam Authority
Dan Lenihan, Omaha Public Power District
Randy Lindstrom, Nebraska Public Power District
Jim McAvoy, Oklahoma Municipal Public Authority
Nathan McNeil, Midwest Energy
Matt McGee, American Electric Power
Alan Myers, ITC Great Plains
Jason Shook, GDS Associates for ETEC
Harold Wyble, Kansas City Power & Light

Other Stakeholders and Staff

Roy Boyer, Southwestern Public Service Company
Julie Denton, City of Independence, MO
Scott Feuerborn, Burns and McDonnell
Jim Flucke, Kansas City Power & Light
Steve Gaw, Wind Coalition
Tony Gott, Associated Electric Cooperative
Rachel Hulett, SPP Staff
Deepthi Kasinaduni, Grand River Dam Authority
Nate Morris, Empire District Electric
Paul Simoneaux, Entergy
Greg Sorenson, SPP RE

Agenda Item 2 – ITP Manual Review

TWG discussed, reviewed and revised the ITP10 portion of the draft ITP manual. One question arose asking for clarification of the purpose of the ITP10 in the manual.

Mo Awad motioned and Alan Myers seconded that TWG approve the ITP manual as modified today. The motion passed with 10 votes for and 1 vote against the motion. Ronnie Frizzell voted against the motion because he would like to review other portions of the manual. (Attachment – ITP Manual)

Noman noted this manual is a living document TWG can revisit in the future.

Agenda Item 3 – Closing

The meeting was adjourned at 12:12 p.m.

Respectfully Submitted,

Rachel Hulett
TWG Secretary

Southwest Power Pool

Southwest Power Pool
TRANSMISSION WORKING GROUP
August 3-4, 2011
Embassy Suites Downtown
Omaha, Nebraska

• A G E N D A •

Wednesday 8:00 a.m. – 5:00 p.m.

1. Administrative .... Noman Williams (5 min)
    a. Call to order
    b. Proxies
    c. Standards of conduct
    d. Approve minutes of previous meetings (Action Item)
        i. May 11-12, 2011
        ii. June 9, 2011
        iii. June 22, 2011
    e. Approve agenda (Action Item)
    f. Meeting Material

2. Review of Past Action Items .... Rachel Hulett (10 min)

3. MOPC/BOD Update .... Noman Williams (15 min)
    a. Action Items

4. MDWG Status Report .... Scott Rainbolt (45 min)
    a. MITF Action Item - Pmax (Travis Hyde) (Action Item)

5. TWG Reports .... Rachel Hulett (15 min)
    a. 3.3.3 Winter 2010 (Scott Jordan)
    b. TWG 2011 work schedule

6. 2011 ITP Activities .... Staff (60 min)
    a. 2011 ITP10
        i. Congestion Results (Bob Lux)
    b. 2011 ITPNT

7. Reactive Studies Update .... Doug Bowman (30 min)
    a. ITP10 results
    b. Near-term update

8. Stability Update .... Scott Jordan (30 min)
    a. DSA tool benchmarking
    b. Voltage criteria

9. EIPC Update .... Doug Bowman (15 min)

10. DC Interconnections Update .... Doug Bowman (15 min)
    a. Clean Line
    b. Tres Amigas

11. Special Protection System – Ensign Wind Farm .... NextEra Energy (15 min)

12. RE, TPL Standards .... Staff (90 min)
    a. RE's 2010 TPL Report Finding (Action Item)
    b. TPL-001-2 Update

13. FAC-010, Planning SOLs Update .... Jason Speer (5 min)

14. RE, 2011 Probabilistic Assessments .... Michael Odom (30 min)

15. Reliability Standards Development Introduction .... Jonathan Hayes (15 min)

Thursday 9:00 a.m. – 12:00 p.m.

16. Project Cost Task Force – Cost Estimating .... Terri Gallup (45 min)
    a. PCTF Whitepaper
    b. Project Cost Working Group
    c. Impacts to Project Tracking

17. Study Estimate Design Guide (DBPPCTF) .... Jake Langthorn (30 min)

18. Interconnection Updates .... All

19. Others .... Everyone
    a. NERC Planning Committee Update
    b. Seams cost allocation update (Noman Williams)
    c. Novations

20. Closing Administrative Duties .... Noman Williams
    a. Summarize Action Items
    b. Discuss upcoming meeting topics
        i. Next Meeting – November 2-3, 2011, Oklahoma City, OK
    c. Adjourn meeting

Southwest Power Pool

Southwest Power Pool, Inc.

TRANSMISSION WORKING GROUP

Pending Action Items Status Report

August 3-4, 2011 – 8:00 a.m.

	Action Item	Date Originated	Status	Comments
1.	Mo Awad and Ed Horgan to update Criteria 12.2 with IEEE references and latest standards.	February 3-4, 2010	In Progress	Update from Mo Awad
2.	Staff to create a work plan for the new TPL-001-1 Standard implementation.	February 3-4, 2010	In Progress	TPL Standard still under development
3.	TWG to ask the Seams Steering Committee and MITF to address the issue of modeling outside transactions in the SPP planning models.	May 12, 2010	In Progress	
4.	Noman to take the LOLE concern to MOPC.	May 13, 2010	In Progress	
5.	Staff to examine Criteria section 3.5 and determine what resources would be required to perform the reviews before NTCs are issued.	August 3-4, 2010	Complete	
6.	Staff to determine if they can benchmark voltages as part of the Criteria 3.3.3 efforts. Staff will focus on EHV voltages initially.	August 3-4, 2010	In Meeting	Discussing opportunities with operations Agenda Item 5a
7.	MDWG to address modeling issues associated with generation reserves: • Need clarity of Pmax definition in the MDWG manual (In the definition, should we allow units to be set to Pmax?) • How do we handle operating reserves in the planning models so either generation outlet issues or import issues are not	September 1, 2010	Complete	Replaced by item 12

Deleted: Don Taylor

Deleted: document all

Deleted: standards listed in Criteria 12.2 that have been revised

Deleted: <#>¶
Staff to write up a request for rating information/proposal to be reviewed and updated by TWG. ... [1]

Deleted: Agenda Item 14a

Deleted: In Meeting

Deleted: <#>¶
Ask operations if they have any data on reactive issues or areas with voltage problems that they can share with TWG. ... [2]

Deleted: Progress

Deleted: MDWG remands issue back to TWG.¶
¶
MDWG can account for operating reserves in the dispatch; problem of generation deficiencies
¶
Update: See MDWG material¶
¶
Agenda Item 5a

Deleted: In Meeting

Southwest Power Pool

	masked?			
8.	Staff to address modeling market dispatch in the 2012 Near-Term Assessment.	November 3-4, 2010	In Progress John Mills	
9.	SPP Staff, ORWG, TWG, and SPCWG to work on Special Protection Schemes policy implemented within criteria to assess and insure the operational and policy perspective. The staff will report back to MOPC in April or July 2011 meeting.	December 17, 2010 MOPC	Complete	
10.	Doug Bowman will contact Randy Lindstrom and John Fulton to discuss DSA tools and benchmarking tests.	February 1, 2011	In Meeting	Agenda Item 8a
11.	Noman and Rachel to further define meeting material proposal	March 1-2, 2011	Complete	
12.	MITF to address how to model generation, either net or gross, in order to more accurately assess system stability.	May 11-12, 2011	In Meeting MITF	Agenda Item 4a
13.	Staff to create report(s) of 2011 Flowgate Assessment and 2011 TRM Assessment by May 20.	May 11-12, 2011	Complete	
14.	Staff to rank the load pockets for the reactive study and ask for member feedback by May 20.	May 11-12, 2011	Complete	
15.	Staff to develop a strawman framework for enhancing the ITP planning process which will phase in coordinated levels of reactive compensation and short circuit analysis for better project cost estimation.	May 11-12, 2011	In Progress Staff	
16.	TWG to consider a task force to enhance the TPL assessments.	May 11-12, 2011	In Meeting	Agenda Item 12a
17.	Ask ORWG to provide clarification in Criteria 5.2.4.1d that "post-contingent bus voltages in excess of +/- 10%" should be the 30-minute allowance.	May 11-12, 2011	Complete	Action Item results concluded in June 9 conference call. Additional action item 18 created.
18.	Members talk to their respective operators to	June 9, 2011	In Meeting	

Deleted: <#>¶
Staff to develop proposal for additional stability analysis which will include comprehensive stability for anticipated EHV facilities. ... [3]

Deleted: <#>¶
Staff to develop a proposal and scope for a baseline reactive study and bring back to TWG by February. ... [4]

Deleted: Agenda Item 15

Deleted: In Meeting

Deleted: <#>¶
ORWG, RTWG, & TWG to resolve the conflict between the Tariff and Criteria about CBM ... [5]

Deleted: Progress

Deleted: Will discuss as part of Agenda Item 1f

Deleted: In Meeting

Deleted: <#>¶
Staff will send out a request in the coming week for the contingencies and input in the 2011 UVLS study ... [6]

	understand and determine if operational studies should use a maximum 1.05 pu voltage limit.			

Page 1: [1] Deleted	Rachel Hulett	6/20/2011 8:15:00 PM

	Staff to write up a request for rating information/proposal to be reviewed and updated by TWG.	May 13, 2010	Complete	

Page 1: [2] Deleted	Rachel Hulett	6/20/2011 8:15:00 PM

	Ask operations if they have any data on reactive issues or areas with voltage problems that they can share with TWG.	August 3-4, 2010	Complete	

Page 2: [3] Deleted	Rachel Hulett	6/20/2011 8:15:00 PM

	Staff to develop proposal for additional stability analysis which will include comprehensive stability for anticipated EHV facilities.	September 1, 2010	Complete	
	Staff to prepare a cost estimate vs. final cost comparison for completed projects.	November 3-4, 2010	Complete	
	Staff to review Tariff language with Dennis Reed and Pat Bourne to ensure compliance with the Tariff in regards to local planning meetings being held at summits.	November 3-4, 2010	Complete	

Page 2: [4] Deleted	Rachel Hulett	6/20/2011 8:15:00 PM

	Staff to develop a proposal and scope for a baseline reactive study and bring back to TWG by February.	November 3-4, 2010	Complete	Preliminary study results will be discussed in a near future meeting
	Staff to bring educational presentation of Attachment AQ to TWG in February.	November 3-4, 2010	Complete	
	Staff to work with SPP Compliance to determine if a CBM Implementation Document needs to be created based on existing Criteria and Tariff language per MOD Standard 004.	November 30, 2010	Complete	

Page 2: [5] Deleted	Rachel Hulett	6/20/2011 8:15:00 PM

	ORWG, RTWG, & TWG to resolve the conflict between the Tariff and Criteria about CBM.	January 12, 2011 MOPC	Complete	

	Staff will send out a request in the coming week for the contingencies and input in the 2011 UVLS study	March 1-2, 2011	Complete	Request sent out March 4. Item will be discussed as part of item 4c.


Helping our members work together to keep the lights on...
today and in the future
SPP Southwest Power Pool

SPP Criteria 3.3.3

2010/11 Winter Peak

August 3, 2011

Southwest Power Pool

SPP Criteria

3.3.3 Benchmark SPP Models

- SPP staff shall benchmark model data against actual SPP system conditions (e.g., generation dispatch, load, and load power factor) which correspond to the time frames for which the models are created. As a minimum the results shall be reported semiannually.

Southwest Power Pool Criteria 3.3.3 - 2010/11 Winter Peak Area Actual Peak & Planning Peak Load Comparison								
Area Num	Area Name	Actual Peak Load Date/Hour	Actual Real-Time Load	Planning Peak Load*	MW Difference	% Difference	eDNA Data Point	Notes
502	CLEC	2/2/2011 7:10	2306	2237	-69	-3.1%	SPP.EMS.00006598	
503	LAFA	1/12/2011 6:20	405	384	-21	-5.5%	SPP.EMS.00036694	
504	LEPA	2/11/2011 7:00	183	172	-10	-6.1%	SPP.EMS.00008044	
515	SPA	1/12/2011 7:20	1246	1224	-22	-1.8%	SPP.EMS.00008939	Includes SPRM, AECC (10%)
520	CSWS|AEPW	2/1/2011 18:40	8104	8049	-54	-0.7%	SPP.EMS.00006775	Includes OMPA (25%), AECC (90%)
523	GRDA	1/12/2011 7:20	727	719	-8	-1.0%	SPP.EMS.00007327	
524	OKGE	2/1/2011 18:20	4876	4756	-121	-2.5%	SPP.EMS.00008570	Includes OMPA (70%)
525	WFEC	2/10/2011 7:00	1525	1356	-170	-12.5%	SPP.EMS.00009409	Includes OMPA (5%)
526	SPS	2/8/2011 20:30	4242	3917	-325	-8.3%	SPP.EMS.00008973	
534	SECI	2/1/2011 11:10	761	699	-63	-8.9%	SPP.EMS.00008879	Includes MKEC
536	WR	2/8/2011 18:30	4629	4368	-261	-6.0%	SPP.EMS.00009470	Includes MIDW
540	MPS	2/10/2011 7:20	1591	1555	-36	-2.3%	SPP.EMS.00008345	
541	KCPL	2/8/2011 18:50	2719	2633	-86	-3.3%	SPP.EMS.00009828	
542	KACY	2/8/2011 18:30	381	364	-18	-4.9%	SPP.EMS.00007704	
544	EDE	2/10/2011 7:10	1160	1149	-11	-1.0%	SPP.EMS.00006934	
545	INDN	2/8/2011 18:40	190	174	-17	-9.5%	SPP.EMS.00006668	
640	NPPD	2/1/2011 10:20	2656	2486	-170	-6.9%	SPP.CALC.NPPDMKTL	
645	OPPD	2/1/2011 18:10	1838	1742	-95	-5.5%	SPP.EMS.00018125	
650	LES	2/1/2011 18:00	575	519	-56	-10.8%	SPP.EMS.00018105	

*Note: Planning Peak Load is Load + Losses to compare to the Actual Load reported via ICCP in real-time.

Criteria 3.3.3 - Trends
Area Actual Peak & Planning Peak Load Comparison

Area Num	Area Name	Summer Peak 2009 Actual Load (MW)	Summer Peak 2009 Planning Peak Load (MW)	Summer Peak 2010 Actual Load (MW)	Summer Peak 2010 Planning Peak Load (MW)	Winter Peak 2009/10 Actual Load (MW)	Winter Peak 2009/10 Planning Peak Load (MW)	Winter Peak 2010/11 Actual Load (MW)	Winter Peak 2010/11 Planning Peak Load (MW)	Summer Peak 2009 Difference	Summer Peak 2010 Difference	Winter Peak 2009/10 Difference	Winter Peak 2010/11 Difference
502	CELE	2651	2448	2472	2380	2456	2218	2306	2237	-8.3%	-3.9%	-10.7%	-3.1%
503	LAFA	475	482	470	487	408	321	405	384	1.4%	3.6%	-26.8%	-5.5%
504	LEPA	229	224	233	225	194	151	183	172	-2.2%	-3.4%	-28.7%	-6.1%
515	SWPA	1571	1649	1634	1680	1303	1253	1246	1224	4.7%	2.7%	-4.0%	-1.8%
520	AEPW	9728	10169	10247	10408	8424	8064	8104	8049	4.3%	1.6%	-4.5%	-0.7%
523	GRDA	862	1018	922	906	751	783	727	719	15.4%	-1.8%	4.1%	-1.0%
524	OKGE	6369	6578	6648	6456	4955	4565	4876	4756	3.2%	-3.0%	-8.5%	-2.5%
525	WFEC	1466	1406	1477	1481	1537	1260	1525	1356	-4.3%	0.3%	-22.0%	-12.5%
526	SPS	5473	5710	5568	5665	4018	4076	4242	3917	4.2%	1.7%	1.4%	-8.3%
534	SUNC	986	1068	1088.0746	1136	723	872	761	699	7.7%	4.2%	17.1%	-8.9%
536	WERE	5968	6102	6618.6213	6308	4652	4094	4629	4368	2.2%	-4.9%	-13.6%	-6.0%
540	MIPU	1949	1980	1964.1601	1973	1664	1541	1591	1555	1.6%	0.5%	-8.0%	-2.3%
541	KACP	3578	3607	3728.3734	3553	2888	2645	2719	2633	0.8%	-4.9%	-9.2%	-3.3%
542	KACY	483	547	505.44029	547	401	404	381	364	11.7%	7.6%	0.7%	-4.9%
544	EMDE	1087	1185	1158.038	1190	1201	1047	1160	1149	8.3%	2.6%	-14.7%	-1.0%
545	INDN	295	316	304.69159	320	195	177	190	174	6.6%	4.9%	-10.2%	-9.5%
640	NPPD	2854	3560	3261.3118	3453	2515	2806	2656	2486	19.8%	5.6%	10.4%	-6.9%
645	OPPD	2514	2849	2582.879	2673	1918	2075	1838	1742	11.8%	3.4%	7.5%	-5.5%
650	LES	747	818	773.94445	783	584	575	575	519	8.7%	1.2%	-1.6%	-10.8%

Load Forecast Comparisons

- 2010/11 Winter vs 2009/10 Winter
  - 13 modeled areas showed an improvement in load forecasting for the 2010/2011 Winter data
  - MAX and Min Percent Differences
    - -0.7 %
    - -12.5 %

Questions?

SPP 2011 WORK SCHEDULE						
Group	**Task**	**Sub-Task**	**Days**	**Start**	**Stop**	**Status**
SPP MDWG (Powerflow)	**2011 Series MDWG POWER FLOW MODELS**		195	08/09/10	05/06/11	
	Pass 2		45	11/22/10	01/21/11	
	Members	Members Review Pass 1 Final Models	10	11/22/10	12/03/10	✓
	Model Update Meeting		3	12/06/10	12/08/10	
	SPP	Review MOD Projects	3	12/06/10	12/08/10	✓
	Members	Member Data Submission	2	12/06/10	12/07/10	✓
	Members	Member Data Due	0	12/07/10	12/07/10	✓
	SPP	MOD Model Extraction	1	12/07/10	12/07/10	✓
	SPP	Build Pass 2 Initial Models	1	12/07/10	12/07/10	✓
	SPP	Post Pass 2 Initial Models	0	12/08/10	12/08/10	✓
	Update Pass 2 Initial Models		32	12/09/10	01/21/11	
	Members	Members Review Pass 2 Initial Models	6	12/09/10	12/16/10	✓
	Members	Member Review Complete	0	12/16/10	12/16/10	✓
	SPP	Build Pass 2 Final Models	25	12/17/10	01/20/11	✓
	SPP	Post MDWG 2011 Series Build 1 Final Models (Pass 2 Final)	0	01/21/11	01/21/11	✓
	Model Verification		10	01/24/11	02/04/11	
	SPP	AC Analysis of Build 1 Final Models	10	01/24/11	02/04/11	✓
	2011 Series MDWG Build 2		69	02/01/11	05/06/11	
	Model Update with Member Data		69	02/01/11	05/06/11	
	SPP	Review MOD Projects	34	02/01/11	03/18/11	✓
	Members	Submit Build 1 Mitigation Plans	20	02/07/11	03/04/11	✓
	Members	Build 1 Mitigation Plans Due	0	03/04/11	03/04/11	✓
	Members	General Data Submission	24	02/01/11	03/04/11	✓
	Members	General Data Due	0	03/04/11	03/04/11	✓
	Members	2010 STEP Data Submission	17	02/10/11	03/04/11	N/A
	Members	STEP Data Due	0	03/04/11	03/04/11	N/A
	SPP	MOD Model Extraction	2	03/22/11	03/23/11	✓
	SPP	Build Initial Build 2 Models	10	03/24/11	04/06/11	✓
	SPP	Post Initial Build 2 Models For Review	0	04/07/11	04/07/11	✓
	Members	Members Review Initial Build 2 Posted Models	15	04/08/11	04/28/11	✓
	Members	Member Review Due	0	04/28/11	04/28/11	✓
	Members	Members Submit Initial Build 2 Model Changes	15	04/08/11	04/28/11	✓
	Members	Member Changes Due	0	04/28/11	04/28/11	✓
	SPP	Incorporate Changes	20	04/08/11	05/05/11	✓
	SPP	Post MDWG 2011 Series Build 2 Final Models	0	05/06/11	05/06/11	✓
SPP MDWG (Dynamics)	**2011 Series MDWG DYNAMICS MODELS**		99	01/24/11	06/09/11	
	2011 Model Updates		99	01/24/11	06/09/11	
	Initial Data Update		35	01/24/11	03/11/11	
	SPP	Build and Post DYRE Files, Wind Farm Data, and Docureport	10	01/24/11	02/04/11	✓
	Members	Members Submit Data Updates	20	02/07/11	03/04/11	✓
	Members	Member Data Due	0	03/04/11	03/04/11	✓
	SPP	Deliver Model Corrections to DC	5	03/07/11	03/11/11	✓
	Powertech	DC builds initial models and submits issues	20	03/14/11	04/08/11	✓
	Final Data Update		23	04/11/11	05/11/11	
	SPP	Prepare and Post DC Issues	2	04/11/11	04/12/11	✓
	Members	Members Submit Data Updates	15	04/13/11	05/03/11	✓
	Members	Member Data Due	0	05/03/11	05/03/11	✓
	SPP	Model Corrections	5	05/04/11	05/10/11	✓
	SPP	Deliver Model Corrections to DC	1	05/11/11	05/11/11	✓
	Powertech	DC builds and posts final models	10	05/12/11	05/25/11	✓
	SPP	Build Final Models	10	05/26/11	06/08/11	✓
	SPP	Post Final Models	0	07/07/11	07/07/11	✓
SPP TWG	Project Tracking 1st Quarterly	TOTAL	37	12/01/10	01/06/11	✓
	Project Tracking	**T.O.s submit updates**	15	12/01/10	12/15/10	✓
	Project Tracking	**T.O.s submit mitigation plans**	31	12/01/10	12/31/10	✓
	Project Tracking	**T.O. review**	14	12/18/10	12/31/10	✓
	NERC Compliance Reporting TPL 001-004		91	12/01/10	03/01/11	✓
	MRSWS Western ERAG Summer Study (form	TOTAL	102	02/02/11	05/14/11	✓
	MRSWS Western ERAG Summer Study (for	**TWG Comments on Report**	13	04/23/11	05/05/11	✓
	MRSWS Western ERAG Summer Study (for	**TWG Approve SPP Section of Report**	9	05/06/11	05/14/11	✓
	TWG Winter Meeting		2	03/01/11	03/02/11	Dallas, TX
	Flowgate Assessment	TOTAL	116	01/15/11	05/10/11	✓
	Flowgate Assessment	**Review of all subsystem files by T.O.s**	17	01/20/11	02/05/11	✓
	Flowgate Assessment	Run AC analysis	29	02/15/11	03/15/11	✓
	Flowgate Assessment	**Review of FG assessment by T.O.s**	15	04/01/11	04/15/11	✓
	Flowgate Assessment	**Post results for TWG review**	1	04/30/11	04/30/11	✓
	UVLS Study	TOTAL	84	02/16/11	05/10/11	N/A
	UVLS Study	Kick-off with SPCWG scoping study	2	02/16/11	02/17/11	N/A
	UVLS Study	**TWG provides input**	15	03/01/11	03/15/11	N/A
	UVLS Study	Analysis	31	04/01/11	05/01/11	N/A
	UVLS Study	**Draft study report shared with WGs**	9	05/02/11	05/10/11	N/A
	FERC715 Filing	Staff to report the SPP filing is complete	7	03/25/11	03/31/11	✓
	Project Tracking 2nd Quarterly	TOTAL	36	03/03/11	04/07/11	✓
	Project Tracking	**T.O.s submit updates**	15	03/03/11	03/17/11	✓
	Project Tracking	**T.O.s submit mitigation plans**	29	03/03/11	03/31/11	✓
	Project Tracking	**T.O. review**	8	03/24/11	03/31/11	✓
	NERC RAS Summer Report	**TWG Comments on Report**	12	03/29/11	04/09/11	✓
	CBM/TRM Assessment	TOTAL	31	04/15/11	05/15/11	✓
	CBM/TRM Assessment	Calculate existing FG TRMs	15	04/15/11	04/29/11	✓
	CBM/TRM Assessment	Calculate existing/new FG TRMs	15	04/15/11	04/29/11	✓
	CBM/TRM Assessment	**Review of TRM values by T.O.s**	5	05/06/11	05/10/11	✓
	CBM/TRM Assessment	**Post results for TWG review**	0	05/11/11	05/10/11	✓
	Annual Review of ATC Process		86	02/05/11	05/01/11	✓
	Benchmarking of Winter Model		30	05/01/11	05/30/11	✓
	TWG Spring Meeting		2	05/11/11	05/12/11	Tulsa, OK

	NERC RAS Long Range Report (LTRA)	**TWG Comments on Report**	15	06/09/11	06/23/11	✓
	Project Tracking 3rd Quarterly	TOTAL	30	06/08/11	07/07/11	✓
	Project Tracking	**T.O.s submit updates**	15	06/08/11	06/22/11	✓
	Project Tracking	**T.O.s submit mitigation plans**	25	06/08/11	07/02/11	✓
	Project Tracking	**T.O. review**	8	06/25/11	07/02/11	✓
	NERC TPL Assesment, TPL 001-004 - Near T	TOTAL	123	06/15/11	10/15/11	In progress
	Mitigation Review	**T.O. comments/mitigation plans due**	38	07/27/11	09/02/11	In progress
	Report Written and TWG review	**TWG review report**	6	10/31/11	11/05/11	
	NERC TPL Assesment, TPL 001-004 - Long-T	TOTAL	123	06/15/11	10/15/11	In progress
	Mitigation Review	**T.O. comments/mitigation plans due**	38	07/27/11	09/02/11	In progress
	Report Written and TWG review	**TWG review report**	6	10/31/11	11/05/11	
	TWG Summer Meeting		2	08/03/11	08/04/11	Omaha, NE
	Project Tracking 4th Quarterly	TOTAL	37	08/31/11	10/06/11	
	Project Tracking	**T.O.s submit updates**	14	08/31/11	09/13/11	
	Project Tracking	**T.O.s submit mitigation plans**	29	08/31/11	09/28/11	
	Project Tracking	**T.O. review**	9	09/20/11	09/28/11	
	NERC TPL Stability Study		66	09/01/11	11/05/11	
	NERC RAS Winter Report	**TWG Comments on Report**	10	09/14/11	09/23/11	
	Reactive Planning Study		62	10/15/11	12/15/11	
	MRSWS Western ERAG Winter Study (former	TOTAL		N/A	N/A	
	MRSWS Western ERAG Winter Study (form	TWG Comments on Report		N/A	N/A	
	MRSWS Western ERAG Winter Study (form	TWG Approve SPP Section of Report		N/A	N/A	
	MRSWS Western ERAG Long-Term Study (fo	TOTAL	95	08/03/11	11/05/11	In progress
	MRSWS Western ERAG Long-Term Study (	**TWG Comments on Report**	7	10/20/11	10/26/11	
	MRSWS Western ERAG Long-Term Study (	**TWG Approve SPP Section of Report**	5	11/01/11	11/05/11	
	Benchmarking of Summer Model		30	11/01/11	11/30/11	
	TWG Fall Meeting		2	11/02/11	11/03/11	Oklahoma City
SPP ITP Near-Term(12 Month Cycle)	SPP MDWG Model Development		167	8/28/10	2/10/11	✓
	Finalize Scope 2011 Planning Cycle		31	11/1/10	12/1/10	✓
	SPP Planning Model Updates		29	2/1/11	3/1/11	✓
	Identify System Problems	Reliability Assessment	71	2/20/11	5/1/11	✓
	TrueShare Posting of Problems		1	4/26/11	4/26/11	✓
	T.O.s Submit Solutions		25	4/26/11	5/20/11	✓
	Planning Summit		1	7/21/11	7/21/11	Dallas, TX
	Planning Summit Feedback		14	7/21/11	8/3/11	In progress
	TrueShare Posting of Preliminary Solutions		1	7/21/11	7/21/11	✓
	Planning Summit		1	9/15/11	9/15/11	TBD
	Planning Summit Feedback		16	9/15/11	9/30/11	
	STEP/ITP 2012-2022 Report		36	10/11/11	11/15/11	
	Finalize ITP Near-Term Scope for 2012 Planning Cycle		31	11/1/11	12/1/11	
	SPP TWG Endorsement		48	11/15/11	1/1/12	
	SPP MOPC Endorsement		10	1/11/12	1/20/12	
	SPP BOD Approval		11	1/20/12	1/30/12	
	Budgeting and Scoping for Years 2-5 and New/Revised Projects		26	2/1/12	2/26/12	
SPP ITP 10-Year Assessment (TWG involvement only)	**Load Forecast Review**		21	1/15/11	2/4/11	✓
	Constraint Analysis and TWG Review		31	5/1/11	5/31/11	✓
	Stakeholders review AC model (market dispatch)		15	5/23/11	6/6/11	✓
	Reliability Assessment		100	6/8/11	9/15/11	In progress
	Stakeholder feedback on reliability issues		14	7/21/11	8/3/11	In progress
	ITP Workshop		1	7/21/11	7/21/11	✓
	TWG helps develop transmission plans		57	7/21/11	9/15/11	
	Stability Study		91	9/1/11	11/30/11	
	Staff performs analyses		62	9/1/11	11/1/11	
	Stakeholder feedback on stability issues		30	11/1/11	11/30/11	
	ITP Workshop		1	9/15/11	9/15/11	TBD
	STEP/ITP 2012-2022 Report		17	9/15/11	10/1/11	
	SPP TWG Endorsement of Report		20	12/1/11	12/20/11	
	SPP BOD Approval of Report		11	1/20/12	1/30/12	
	Develop scope for 2012 20-Year ITP Assessment		92	9/1/11	12/1/11	
	TWG finalize and approve scope		48	10/15/11	12/1/11	
	Begin 2012 20-Year ITP Asssessment			1/15/12		
SPP Aggregate Study	Aggregate Study 2011-AGP1	(not including reruns) (not including reruns)	60	2/1/11	4/1/11	✓
	Aggregate Study 2011-AG2	(not including reruns)	60	6/1/11	7/30/11	✓
	Aggregate Study 2011-AG3	(not including reruns)	61	10/1/11	11/30/11	

Voltage Stability

July 21, 2011

Douglas Bowman, PE

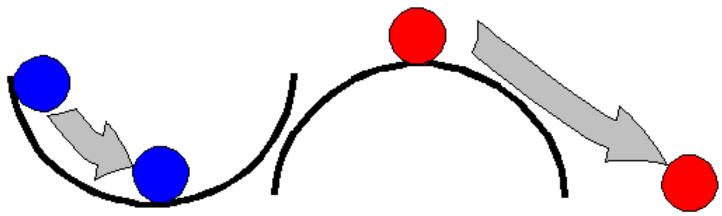
Southwest Power Pool

Objective

- Determine deliverability of wind generation in Future 1
  - How much conventional generation can we successfully displace with wind generation?
  - Is the reactive compensation in the case sufficient to prevent voltage collapse?

Stability

Stability & Instability



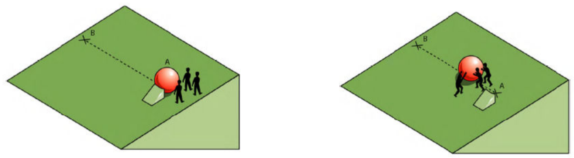
If it returns to it's original position it is **STABLE**

If it does NOT return to it's original position, it is **UNSTABLE**

Voltage Stability

- System's ability to control voltages and prevent voltage collapse
- Requires that system voltages be maintained at acceptable levels during
  - high load levels
  - large power transfers
  - Sudden disturbances (loss of a generator or line)
  - Combinations of the above
- Voltage stability closely related to the system's need for reactive power

Voltage Stability



Simple Reactive Compensation Analogy

Voltage Collapse as a Function of Power Flow

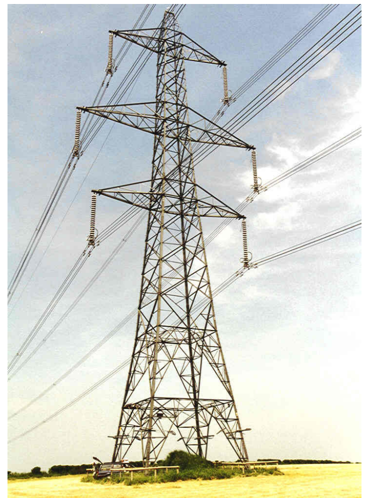
Future 1 Case Assumptions

- Future 1
  - ____ MW wind generation dispatched
  - 729 MVar of new SVCs added to the case

Bus	Voltage	MVAR Generation
Woodward	345kV	429
Hitchland	345kV	113
Potter County	345kV	187
Tuco	345kV	-37

Assumptions – cont'd

- N-1 branch contingencies >100 kV
- SPP Flowgate contingencies
- Monitored elements >100 kV
- Monitored SPP flowgates
- Monitored SPP interfaces



SPP 7

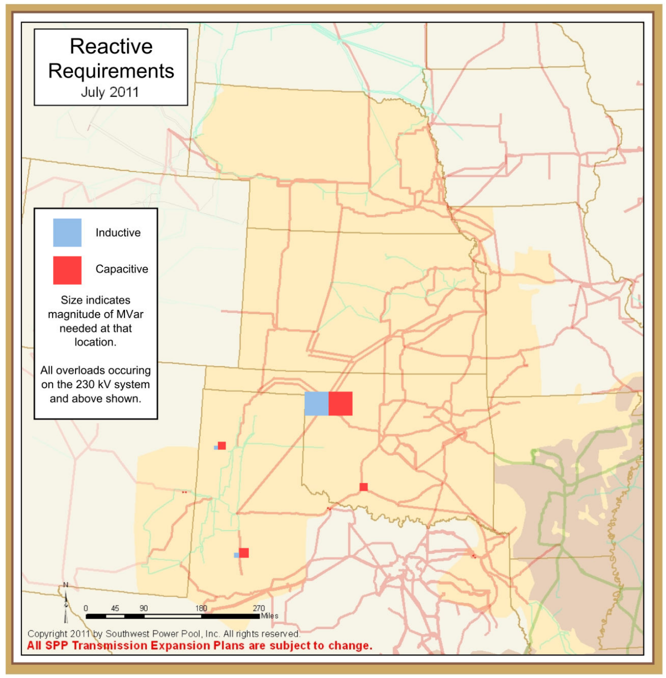
Simulation Results

- No unmanageable voltage collapses within SPP for Future 1
- Inductive Reactance Require: 482 MVar
- Capacitive Reactance Required: 845 MVar

Bus	Voltage	MVar Generation Low Wind	MVar Generation High Wind
Woodward	345 kV	-450	450
Wildorado	230 kV	-12	49
Grassland	230 kV	-20	296
Lawton East	345 kV	0	50

SPP 8

Reactive Requirements



Next Steps

- Perform voltage stability analysis in assisting with determination of final solution
- Prioritized High Load Areas
  - Increase Area Loading
  - Increase adjacent area generation
  - Selected contingencies

SPP 10

SPP Dynamic Stability Update

TWG Meeting

August 3 & 4, 2011

Scott Jordan
sjordan@spp.org · 501.614.3985

SPP Southwest Power Pool

Table of Contents

- DSA Tools and PSS/E Bench Marking
- Transient Stability Criteria
- 2011 TPL Transient Stability Assessment

DSA Tools and PSS/E Bench Marking

- Compared the results of dynamic simulations
  - Case: 2010 Series MDWG 2011 Light Load
  - Use generic WT3 wind models in DSA Tools
- Simulations
  - System Screening Results
    - Comparison of Angular Stability only
    - Both tools indicated the same stable & unstable events
    - DSA Tools saved time both creating the contingency file for the simulation and analyzing results

DSA Tools and PSS/E Bench Marking

- Simulations Cont'.
  - Comparison of Member Submitted Events
    - Comparison of Angular Stability only
    - Events B1, B2, B3, B9, B10, and B19 bench marked
    - B1, B2, B9, B10, and B19 stable with both tools s
      - similar outputs comparing Speed and Angle plots
    - B3 showed unstable with both tools
      - Comparison of Sensitivities
        - » Stable and Unstable sensitivities same for both software packages
        - » Event shown to be stable at 3.6 cycles in both software packages

SPP Transient Stability Criteria

- Proposed SPP Transient Stability Criteria
  - Angular Stability
    - » Any deviation of rotor angle beyond 180 degrees is considered instability of the generator
  - Oscillations should be damped by more than 5%
  - Transient voltage recovery (0 – 20 seconds)
    - » Not to exceed 1.2 pu maximum at any bus
    - » Not to exceed 0.7 pu minimum at any bus
- SPP Staff ran simulations using DSA tools and applying the criteria above.
  - Clearing times critical
  - Software default value for a 3-phase fault (–j2e9 MVA)
  - Re-assess once the short circuit models are finalized

2011 TPL Transient Stability Assessment

- 2011 Series MDWG 2012L and 2017S Cases
- Member Submitted TPL Events
  - 23 NERC Category "B"
  - 17 NERC Category "C"
  - 13 NERC Category "D"
- DSA Tools
  - System Screen
  - Apply Proposed SPP Stability Criteria

SPP 7

Questions or Concerns?

Scott Jordan
sjordan@spp.org · 501.614.3985

SPP 8

EIPC Update

TWG Meeting
Omaha, NE
Aug 21, 2011

Douglas Bowman
dbowman@spp.org· 501.688.1640

SPP Southwest Power Pool

Eastern Interconnection Planning Collaborative

- Commenced May, 2009
- DOE funded
- 26 Planning Authorities
- Multi-constituency stakeholder process
- Extends existing regional planning analysis to include an interconnection wide approach
- Develop interregional transmission expansion options
- Complete studies to support state, regional, and federal public policy goals

SPP 2

EIPC Steps

1. Integrate Regional Plans
2. Perform macroeconomic resource expansion analysis
3. Define scenarios for transmission build-out analysis
4. Develop transmission expansion options for scenarios

EIPC Completed Tasks

1. Integrate regional plans
   - ✓ Aggregate regional models
   - ✓ Add identified inter-regional efficiency opportunities
   - ✓ Perform inter-regional analysis
2. Perform macroeconomic resource expansion analysis
   - ✓ 8 macroeconomic resource expansion futures
   - ✓ Up to 9 sensitivities for each future
   - ✓ A few key results include
     - ✓ New capacity additions and retirements by type
     - ✓ Fuel prices and consumption
     - ✓ High level transmission congestion

Macroeconomic Futures

- Futures
  - F1 – "Business as Usual"
  - F2 – Nationally Implemented Federal Carbon Constraint
  - F3 – Regionally Implemented Federal Carbon Constraint
  - F4 – Aggressive EE/DR/DG/Smart Grid
  - F5 – National RPS – Top Down Implementation
  - F6 – National RPS – State/Regional Implementation
  - F7 – Nuclear Resurgence
  - F8 – Combined Federal Climate and Energy Policy
- Sensitivities
  - High/low load growth, fuel prices, EE/DR/DG/SG, etc.

SPP 5

EIPC Next Steps

3. Define 3 scenarios for transmission build-out options (by 12/31/2011)
   - Taken from futures/sensitivities in macro studies
   - Stakeholder consensus and guidance
   - State supported
4. Develop transmission expansion options for scenarios (by 12/31/2012)
   - Perform Reliability analysis
   - Perform Production cost analysis
   - Develop high level G & T cost estimates

SPP 6

Questions

NextEra Energy Resources' 99 MW Ensign Wind Farm

Automatic Control System (ACS) & Special Protection System (SPS)

Madan Gaudi, Transmission Manager

TWG Meeting - 08/03/2011

Madan Gaudi's Work Experience

- **System Operation Planning: 1981-1991 FP&L Co.**
  Loadflow and stability studies for transfer limits, outages, reactive control settings and other issues, simulation of system disturbances, etc.

- **System Protection & Control: 1991-2001 FP&L Co.**
  Relaying philosophies, short-circuit studies and protective relay settings for transmission lines, transformers, generators, shunt devices, etc.

- **Transmission Planning & Development: 2001- To Date NextEra Energy Resources**
  Generator Interconnections and transmission studies for several fossil plants and about thirty wind farms in ERCOT, SPP and other markets.

2

Agenda

- Purpose
- Ensign One-Line Diagram
- Area Transmission Overview and
  Worst Contingency and Limiting Element
- SPP Solution
- NextEra's Temporary Solution – ACS and SPS
- Overall Operation of the ACS and SPS
- Automatic Control System (ACS)
- Special Protection System (SPS)
- Physical Connections between Various Devices
- Conclusion

NEXTera ENERGY RESOURCES

3

Purpose

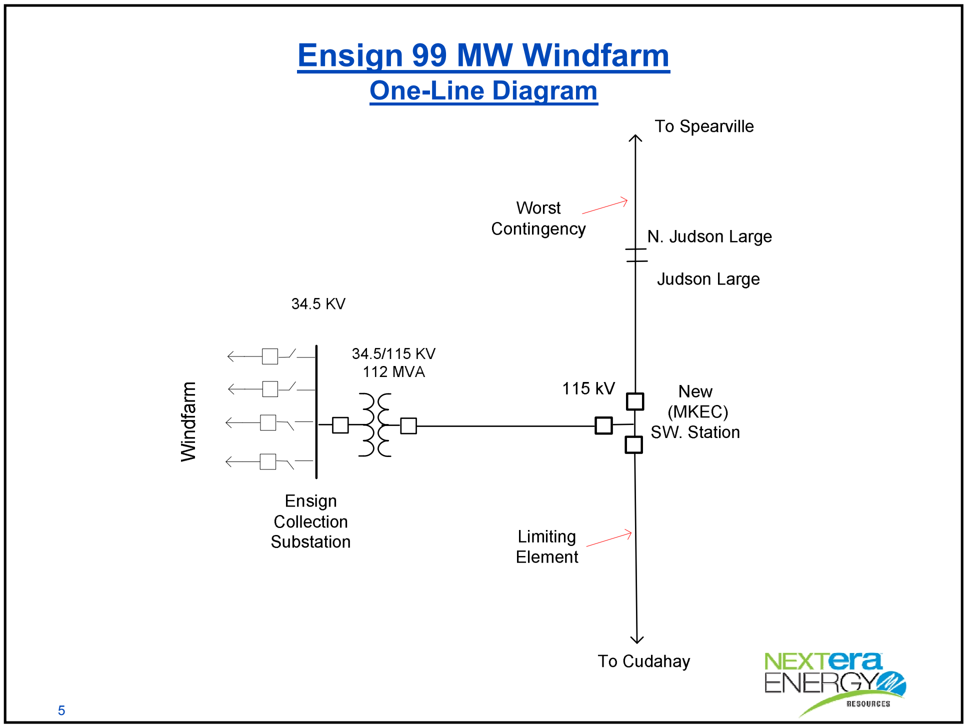
- Allow NextEra's Ensign project to be interconnected with opportunity to operate up from its current SPP imposed operating limit of 31MW to its full potential

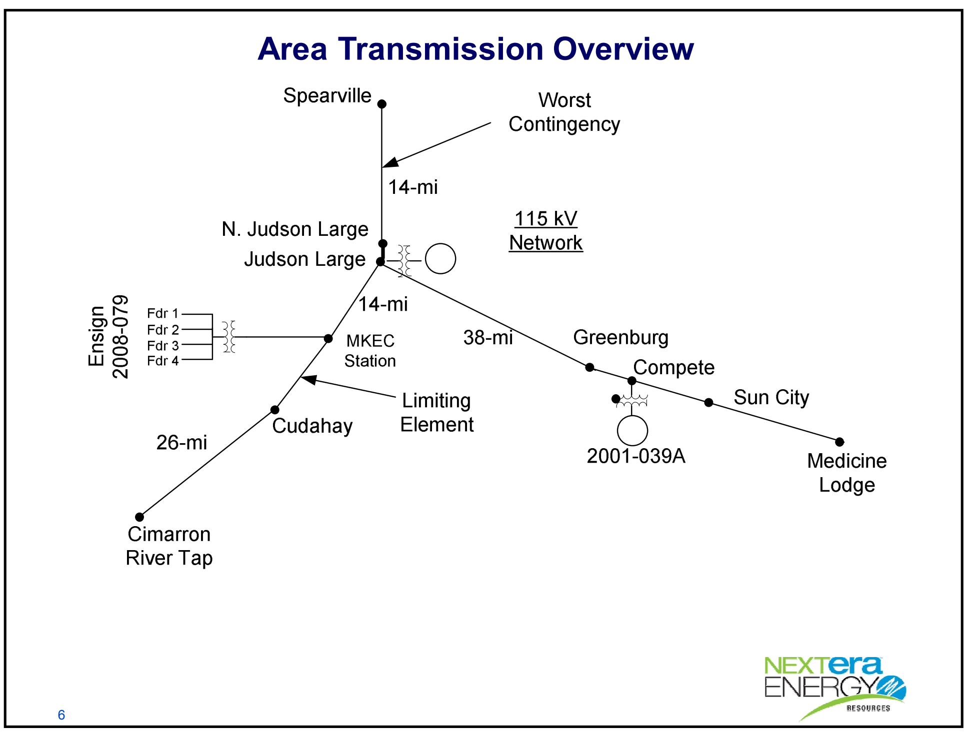
- Ensure that reliability of the SPP grid is not compromised. Install a reliable Automatic Control System (ACS) and a Special Protection Scheme (SPS)

- ACS/SPS would only be in effect until necessary network upgrades are in place (projected in service date: December 2014)

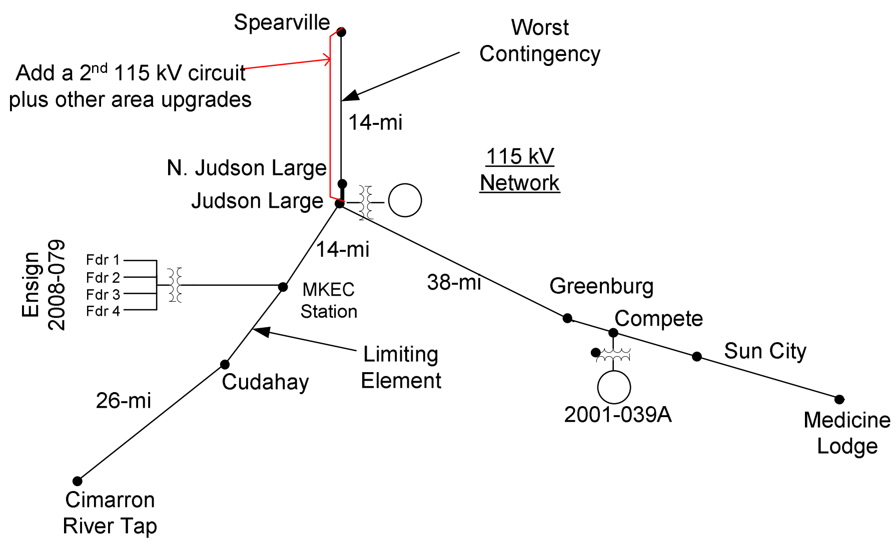
NEXTera ENERGY RESOURCES

4


Ensign 99 MW Windfarm
One-Line Diagram
To Spearville
Worst
Contingency
N. Judson Large
Judson Large
34.5 KV
34.5/115 KV
112 MVA
Windfarm
115 kV
New
(MKEC)
SW. Station
Ensign
Collection
Substation
Limiting
Element
To Cudahay
NEXTera ENERGY RESOURCES
5


Area Transmission Overview
Spearville
Worst
Contingency
14-mi
N. Judson Large
Judson Large
115 kV
Network
Ensign
2008-079
Fdr 1
Fdr 2
Fdr 3
Fdr 4
14-mi
MKEC
Station
38-mi
Greenburg
Compete
Sun City
Limiting
Element
Cudahay
26-mi
2001-039A
Medicine
Lodge
Cimarron
River Tap
NEXTera ENERGY RESOURCES
6

SPP Solution



7

NextEra's Temporary Solution

Two Prong Approach:

- **Control the flow on the limiting line by an Automatic Control System (ACS):**

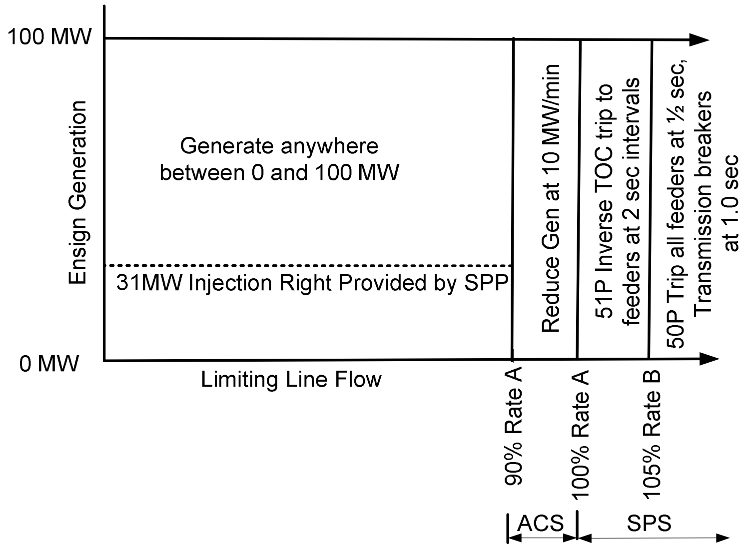
  Monitor the flow on the MKEC Station. – Cudahay line and provide inputs to the Ensign Wind Farm Management System (WFMS). The WFMS would curtail generation when the line loading exceeds 90% of Rate A.

- **Install a Special Protection System (SPS) as a Backup:**

  In the event of a system contingency or the failure of the ACS, if the MKEC Station. - Cudahay line does become overloaded, the SPS will trip generation from Ensign Wind and alleviate the overload.

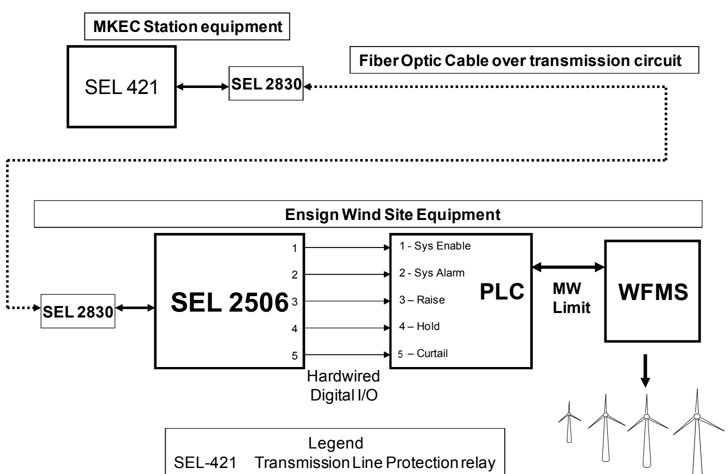
8

Overall Operation of ACS and SPS



9

Automatic Control System (ACS)



Legend	
SEL-421	Transmission Line Protection relay
SEL-2830	Fiber optic Transceiver
SEL-2506	Remote Input / Output Module
PLC	Programmable Logic Control
WFMS	Wind Farm Management System

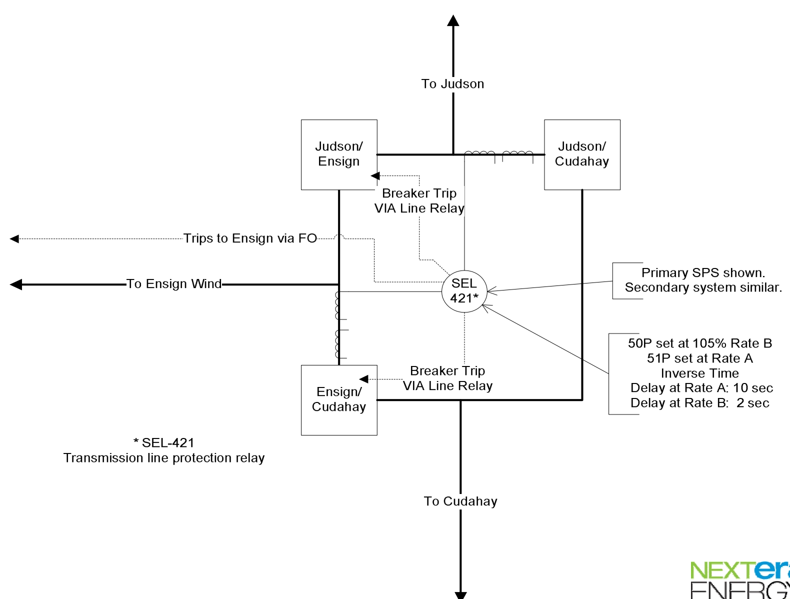
10

Automatic Control System (ACS) contd.

Cudahay Line Load	Time Delay **	Result
More than 100% Rate A	2 sec	Trip first feeder
More than 100% Rate A	4 sec	Trip second feeder
More than 100% Rate A	6 sec	Trip third feeder
More than 100% Rate A	8 sec	Trip fourth feeder
More than 100% Rate A	10 sec	Trip 115KV Ensign breakers at MKEC sub
More than 105% Rate B	1/2 sec	Trip all Ensign feeders simultaneously
More than 105% Rate B	1 sec	Trip 115KV Ensign breakers at MKEC sub
** This time delay is after the 50P-TOC relay element operates. For example, total delay at minimum pickup (100% rate A) is the 51P-TOC time delay plus trip time delay = 12 Sec		

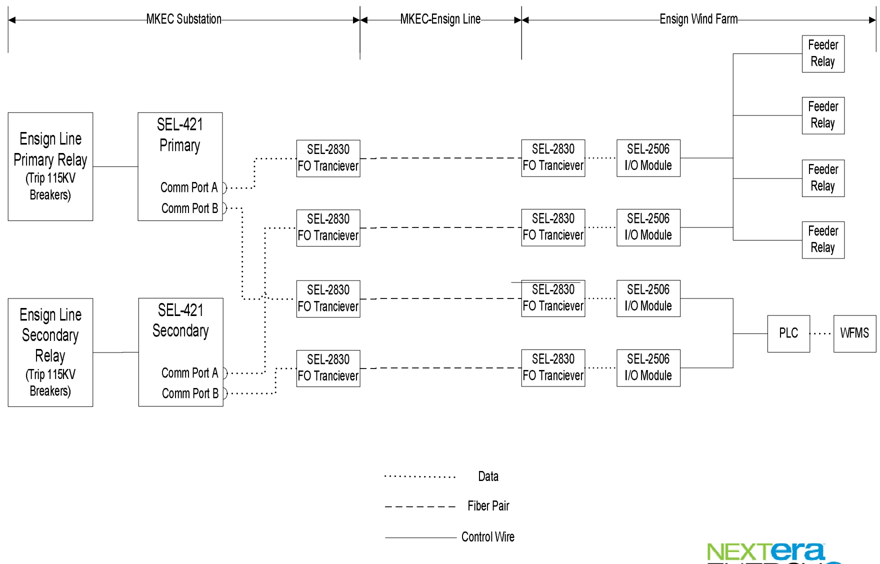
11

Special Protection System



12

Physical Connections Between Various Devices



13

Conclusion:

Proposed ACS/SPS will achieve our intended purpose.

Questions ???

14

Ensign Wind Farm (GEN-2008-079)

Proposed Automatic Control System (ACS) and Special Protection System (SPS) Design Description

Ensign Control and SPS rev 2
6/20/2011

Overview

Ensign Wind is a 100MW site that will connect into a new MKEC, three terminal ring bus station to be constructed on the Judson Large - Cudahay 115kV line about 14 circuit miles from Judson Large. (Figure 1). This document describes a proposed Automatic Control System (ACS) for the Ensign windfarm and a proposed Special Protection System (SPS) for the new MKEC station. (Station referred to as "MKEC switching station" for the purpose of this document.)

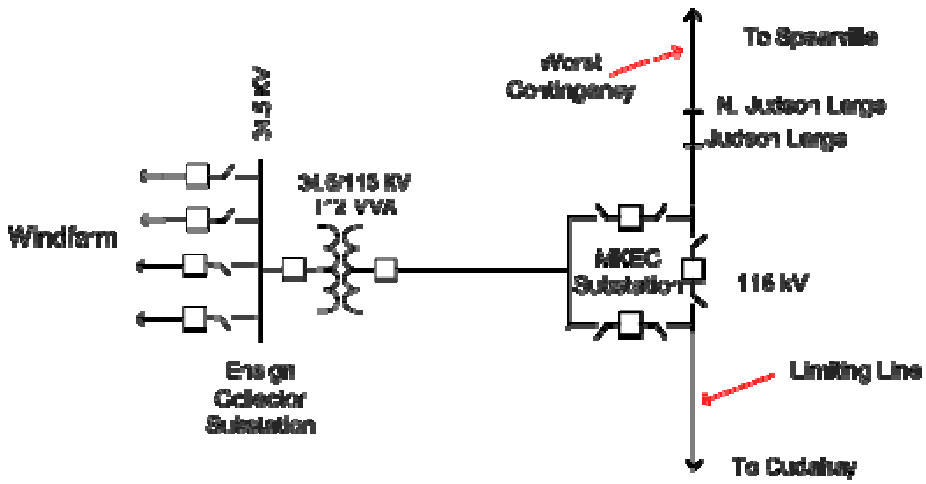


Figure 1 – Ensign One Line

Problem

Depending on the status of other generation in the area, the generation from Ensign can contribute to loading the MKEC – Cudahay 115KV line beyond its normal Rate A. This loading can also exceed the short term rate B under system contingencies. The largest contingency for Ensign Wind is the trip of the North Judson Large – Spearville 115kV line (Figure 2).

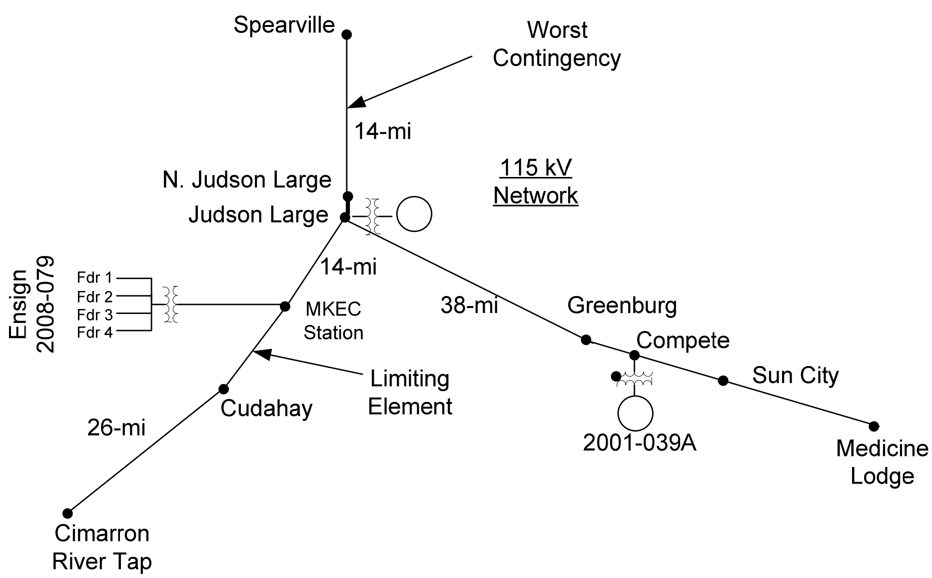


Figure 2 – Area One Line

Temporary Solution:

An automatic control system (ACS) would curtail the windfarm output to limit the flow on the MKEC Station – Cudahay line to 90% Rate A. A Special Protection System (SPS) would alleviate any overloads in the event of any system contingency or the failure of the ACS system. (Figure 3)

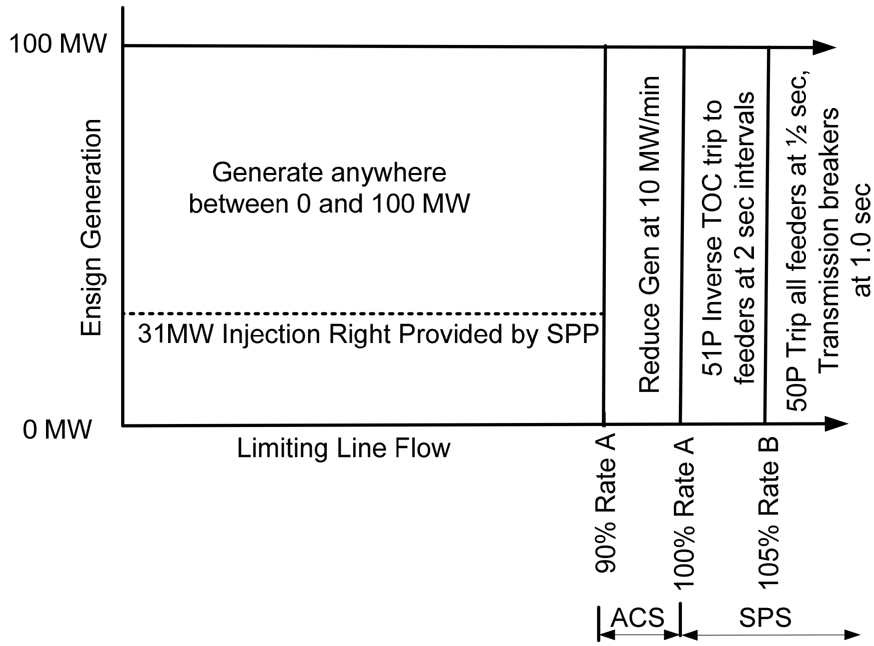


Figure 3 – Overall Operation of the ACS and SPS

Permanent Solution:

Future construction of a second North Judson Large – Spearville line should eliminate the single contingency exposure to overloading the MKEC Station – Cudahay line and make it possible to retire the ACS and SPS. This SPS is expected to be in service for three years.

Automatic Control System (ACS)

To prevent overloads on the MKEC Station - Cudahay 115 kV line, the proposed ACS would be used to monitor the flow on this line and provide inputs to the Ensign Wind Farm Management System (WFMS). The WFMS would curtail generation when the load on the MKEC –Cudahay line exceeds 90% of Rate A (Figure 4).

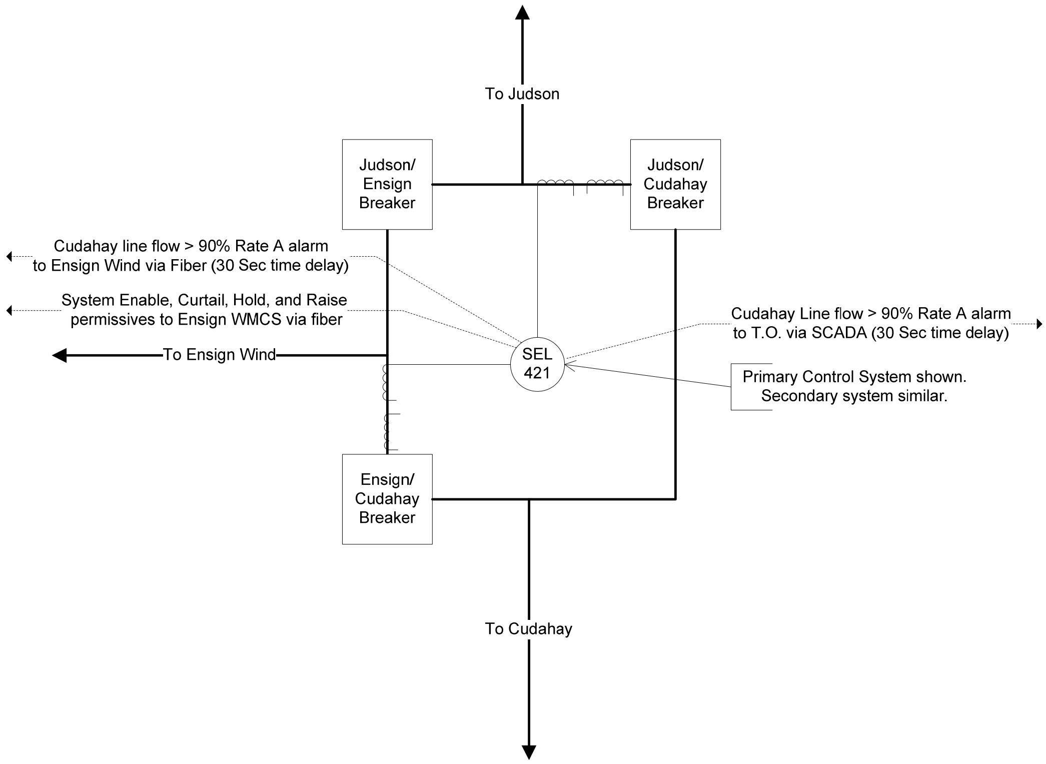


Figure 4 – Automatic Control System

The proposed ACS will use redundant Schweitzer SEL-421 line protection relays to measure current on the Cudahay line and will communicate to the wind site over fiber optic cable to two Schweitzer SEL-2506 Remote Input/Output (I/O) modules located at Ensign Wind. The SEL-2506 I/O modules will interface with a Programmable Logic Controller (PLC) for the WFMS.

The intent of this system will not be to control the wind site directly, but to provide permissive signals to the WFMS based on system conditions. The signals from the MKEC substation and response at Ensign Wind will be: 1) Enable – ACS in service and functioning, 2) Alarm – ACS problem, control may not be reliable, 3) Raise – Line flow less than 85% of rate A, OK to raise, lower, or maintain current output, 4) Hold – Line flow from 85% to 90% of Rate A, OK to lower generation or regulate at current level, 5) Curtail –line flow greater than 90% of Rate A, begin lowering output at a rate of 10MW per minute. The control system will send an alarm to the T.O. and G.O. if the Cudahay line flow exceeds 90% of Rate A for more than 30 seconds. (Figure 5)

The control system will use logic elements and line current measurements from the SEL-421 SPS relays, but will not be part of the SPS.

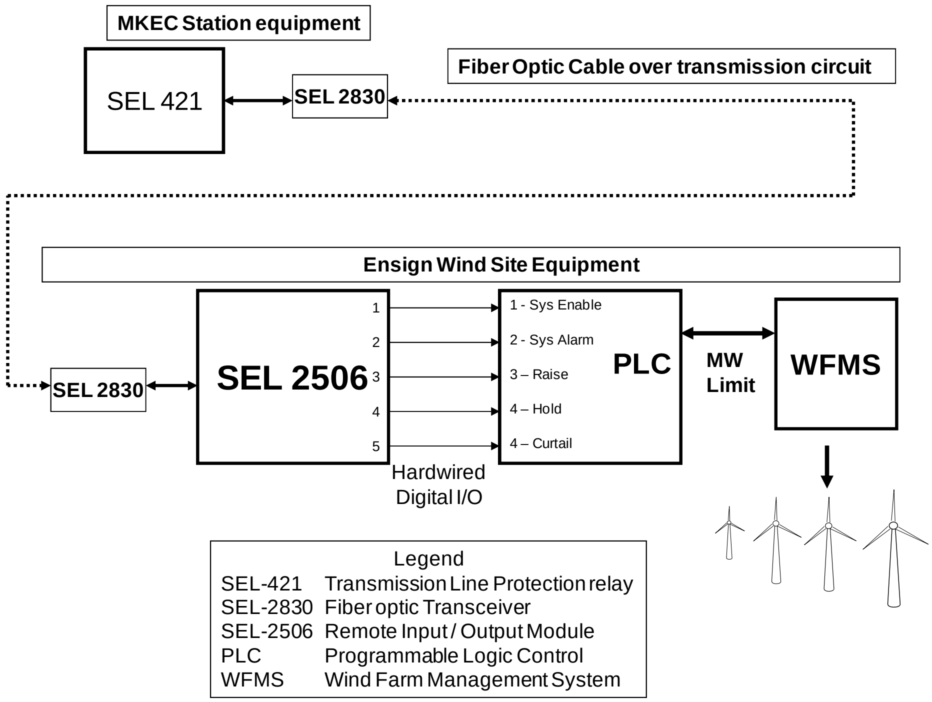


Figure 5 – Automatic Control System Detail (Redundant system not shown)

Proposed Special Protection System (SPS)

The control system outlined above should limit the Cudahay line flow to 90% of Rate A. If upon a system contingency or the failure of the ACS, the Cudahay line does become overloaded, the SPS will trip generation from Ensign Wind and alleviate the overload.

The proposed SPS will measure the current at the MKEC station on the Cudahay line and trip feeder breakers at Ensign Wind if any phase current on the Cudahay line exceeds the relay setpoint. In addition, the scheme will trip the two transmission breakers for the Ensign Wind tie at the MKEC station as backup if the overload persists after attempting to trip all four feeders at Ensign Wind (Figure 6).

This SPS will consist of two Schweitzer SEL-421 relays, one each connected in the primary and secondary phase Current Transformer (CT) circuits in series with the line protection relays. The two SEL-421 relays will trip from one to four 34.5KV feeders at Ensign Wind via fiber optic to two Schweitzer SEL-2506 Remote I /O modules at the wind site switchyard, and if necessary, will trip the primary and secondary trip circuits respectively for the two Ensign Wind 115KV tie breakers at the MKEC substation as a backup to the feeder trips. The SPS relays will also provide alarm outputs for trip circuit trouble and relay trouble. The two SEL-421 relays will be connected to separate DC circuits. The two circuits should be supplied from separate battery banks unless SPP determines that a single battery bank is acceptable.

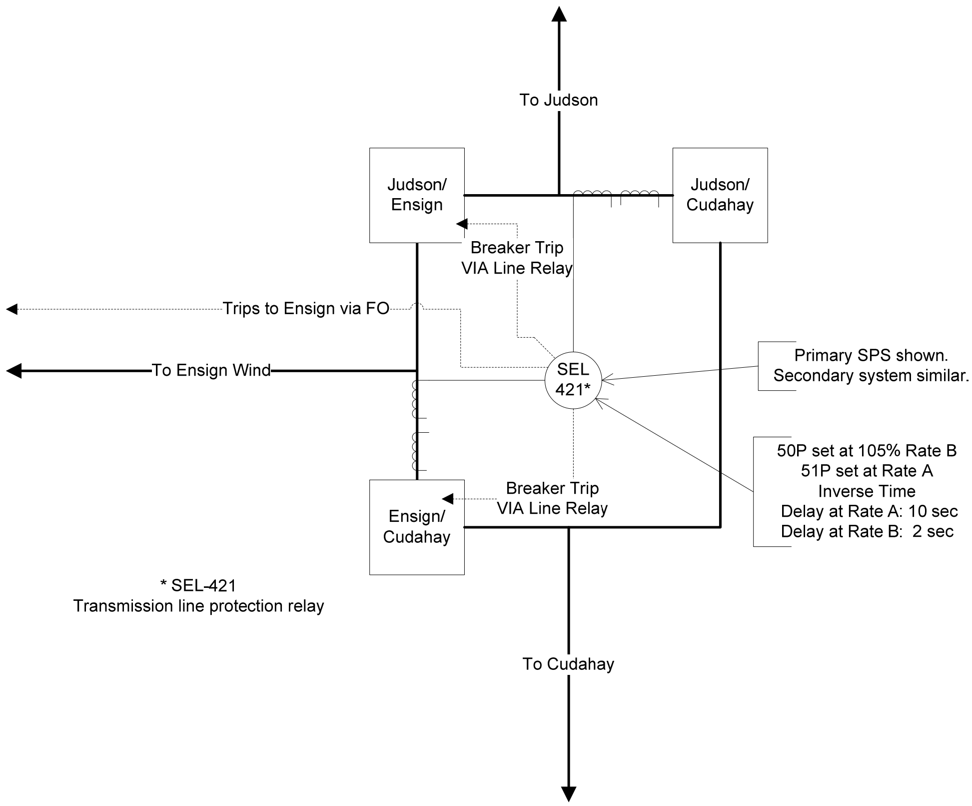


Figure 6 – Special Protection System One Line

The SPS relays will be set with: 1) A time delay overcurrent element (51P-TOC) with the delay inversely proportional to the overload current. The element will operate after 10 seconds at Rate A, and two seconds at Rate B, and 2) An instantaneous overcurrent element (50P) set to operate at 105% of Rate B.

If Cudahay line loading remains between Rate A and 105% of Rate B long enough to pick up the 51P-TOC element, the SPS will begin tripping feeders at Ensign Wind at 2 second intervals until Cudahay loading decreases to less than Rate A. If the condition persists for 2 more seconds after attempting to trip all four Ensign feeders, then the SPS will trip the Ensign transmission breakers at MKEC station.
Further, if loading on the Cudahay line exceeds 105% of Rate B, the SPS will, after ½ second, trip all four feeders simultaneously, and if that condition persists for an additional ½ second, the SPS will trip the Ensign transmission breakers. (Figure 7)

The SEL-421 relays will also be used as elements of the non-SPS control system described above.

Cudahay Line Load	Time Delay **	Result
Between Rate A and 105% Rate B	2 sec	Trip first feeder
Between Rate A and 105% Rate B	4 sec	Trip second feeder
Between Rate A and 105% Rate B	6 sec	Trip third feeder
Between Rate A and 105% Rate B	8 sec	Trip fourth feeder
Between Rate A and 105% Rate B	10 sec	Trip 115KV breakers at Ensign
More than 105% Rate B	1/2 sec	Trip all Ensign feeders simultaneously
More than 105% Rate B	1 sec	Trip 115KV breakers at Ensign
** This time delay is after the 50P-TOC relay element operates. For example, total delay at minimum pickup (100% rate A) is the 51P-TOC time delay plus trip time delay = 12 Sec		

Figure 7 – SPS Trip Table

Summary

An overall interconnection sketch of the proposed ACS and SPS is shown in Figure 8. The design is based on Cudahay line Rate A and Rate B. Since there are different winter and summer values for rates A and B, the relays will be programmed with different winter and summer settings that will be able to be changed either locally or via remote communications.

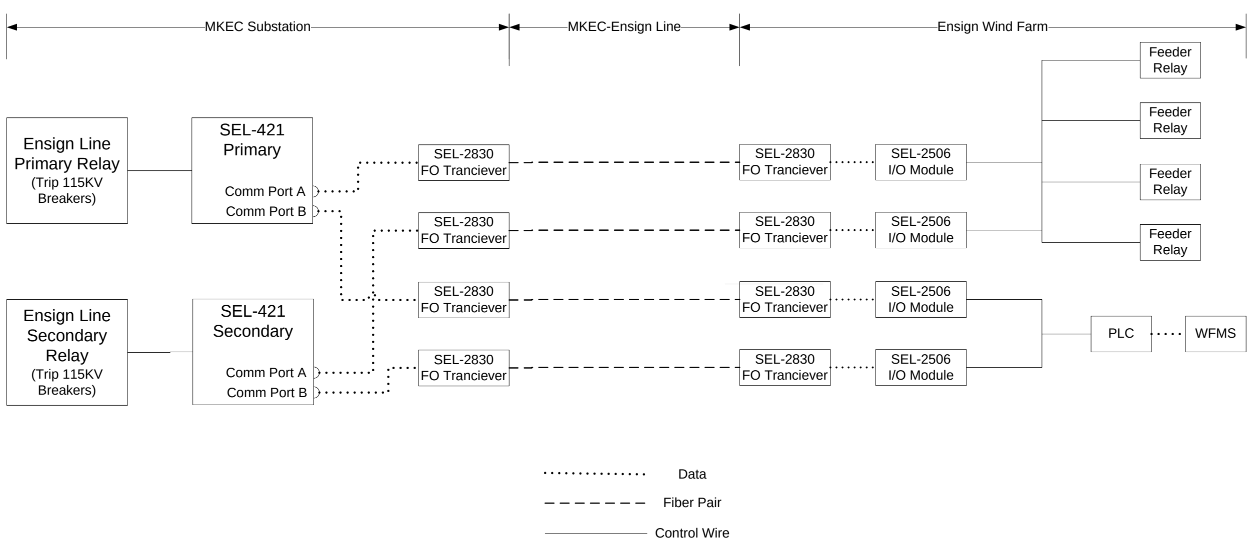


Figure 8 – Overall Interconnection of the ACS and SPS

2010 TPL Review

August 2011

SPP Southwest Power Pool

Section 1

SPP RE RECOMMENDATIONS

SPP RE Recommendations

- **Model verification**
  - Transmission Planners should continue to resolve naming issues to reduce ambiguity.
- **OPM solution verification**
  - TWG should review the OPM rules being applied to the next year's study and consider when the solution requires additional review by the company and procedure for documenting such review. This review should indicate that the company agrees with the result or proposes an alternative solution.
- **Non-OPM solution review**
  - Transmission Planners should ensure that mitigation plans are updated and documented for all projects that are behind schedule. TPs should ensure that valid operating guides are developed if that is the chosen method of addressing contingencies.

SPP RE Conclusion

- While the TWG TPL study can serve as a basis for the assessment, it is not a sufficient document in and of itself. TPs need to have a document that shows their assessment of the inputs of the study, that shows that their system is sufficiently studied under all the TPL standards, the current status of the projects is considered, that projects delayed due to challenges in the construction process are mitigated, and that operating guides are developed, maintained, and reviewed to ensure they are capable of being implemented in the time required to solve the problems identified by the studies.

SPP 5

Section 2

CHANGES/IMPROVEMENTS

SPP 6

OPM Solutions

- Current OPM operations
  - MW re-dispatch
  - Mvar re-dispatch
  - Line switching
  - Load curtailment (Category C and D)
- Some violations are solved by more than 10 OPM steps.
- Do we need to limit the number of OPM steps per violation?

❑ SPP RTO Recommendation

- TPs should review the OPM measures for their area to determine if they are adequate or if they need an alternate solution.

Contingencies

- 2011 TPL Contingencies (Automatically Selected)
  - 2012 Fall (675,480)
  - 2012 Spring (669,300)
  - 2012 Summer (853,228)
  - 2013 Winter (683,692)
  - 2013 Summer (865,671)
  - 2017 Winter (730,618)
  - 2022 Summer (979,985)

(N-2) Category	Selection Rule
Branch-Branch	Same Zone
Branch-Generator	Same Area
Generator-Generator	All Modeled

- NERC TPL-003
  - R1.3.1 states "Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts."

❑ SPP RTO Recommendation

- Remove 69kV branches from the contingency lists.

Transmission Planner Assessment

- Each TP must perform its own TPL assessment.
- 2010 TPL Documents
  - SPP TPL Report
  - Individual TP assessment
- 2011 TPL Documents
  - Same as 2010 or combine individual TP's assessments with the SPP report into one master TPL report?

- SPP RTO Recommendation
  - Create a master TPL report including each TP's individual assessment.

SPP | 9

SPP Southwest Power Pool

Jason Speer
501-614-3301
questions@spp.org

SPP | 10

Standard Number	Req. #	Text of Requirement	Violation Risk Factor	Time Horizon	Gap Yes/No	Possible Evidence	Gap Description	Mitigation Planner	Remarks	Resources
TPL-001-2	***R1.***	***Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1.***	Medium	Long-Term Planning	No					
TPL-001-2	R1.1.	System models shall represent:			No					
TPL-001-2	R1.1.1.	Existing Facilities			No					
TPL-001-2	R1.1.2.	Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.			Yes	Steady State, Short Circuit, & Stability Analysis	This data will be added to the MDWG request for the 2011 Series models.	MDWG		
TPL-001-2	R1.1.3.	New planned Facilities and changes to existing Facilities.			No					
TPL-001-2	R1.1.4.	Real and reactive Load forecasts.			No					
TPL-001-2	R1.1.5.	Known commitments for Firm Transmission Service and Interchange.			No					
TPL-001-2	R1.1.6.	Resources (supply or demand side) required for Load.			No					
TPL-001-2	***R2.***	***Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6) , document assumptions, and document summarized results of the steady state anlyses, short circuit analyses, and Stability analyses.***	High	Long-Term Planning	Yes	Short Circuit Analysis	We do not have short circuit models. Do not currently perform short circuit studies.	Doug Bowman	Developing short circuit processes and models for 2011 Model Series	
TPL-001-2	R2.1.	For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies (as indicated in Requirement R2, Part 2.6). Qualifying studies need to include the following conditions:			No					
TPL-001-2	R2.1.1.	System peak Load for either Year One or year two, and for year five.			Yes	Steady State Analysis	We do not have year five model.	Doug Bowman		
TPL-001-2	R2.1.2.	System Off-Peak Load for one of the five years.			Yes	Steady State Analysis	We do not currently use an off-peak load model.	Jason Speer		
TPL-001-2	R2.1.3.	P1 events in Table 1 with known outages modeled, as in Requirement R1, part1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled.			Yes	Steady State Analysis	We do not currently use an off-peak load model.	Jason Speer		
TPL-001-2	R2.1.4.	For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measureable change in System response: • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of known Transmission outages.			Yes	Steady State, Sensitivity Analysis	R2.1.1 and R2.1.2 are not met.	Jason Speer	Need to develop on sensitivity Scenario models	
TPL-001-2	R2.1.5.	When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.			Yes	Steady State Analysis	Spare equipment strategy is not factored in our current TPL assessment.	Jason Speer		
TPL-001-2	R2.2.	For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:			No					
TPL-001-2	R2.2.1.	A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.			No					

Standard Number	Req. #	Text of Requirement	Violation Risk Factor	Time Horizon	Gap Yes/No	Possible Evidence	Gap Description	Mitigation Planner	Remarks	Resources
TPL-001-2	R2.3.	The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.			Yes	Short Circuit Analysis	Development of study scope to be completed for 2011 Model Series.	Doug Bowman		
TPL-001-2	R2.4.	For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required:			Yes	Stability Study Analysis		Scott Jordan		
TPL-001-2	R2.4.1.	System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.			Yes	Stability Study Analysis	Addition of a Near-Term Peak Model Assessment	Scott Jordan		
TPL-001-2	R2.4.2.	System Off-Peak Load for one of the five years.			No					
TPL-001-2	R.2.4.3.	For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: • Load level, Load forecast, or dynamic Load model assumptions. • Expected transfers • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.			Yes	Stability Analysis	Addition of a Near-Term Peak Model Assessment	Scott Jordan	Need to develop on sensitivity Scenario models	
TPL-001-2	R2.5.	For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part 2.6 and shall include documentation to support the technical rationale for determining material changes.			Yes	Stability Analysis	Addition of a Long-Term Study Model Assessment	Scott Jordan		
TPL-001-2	R2.6.	Past studies may be used to support the Planning Assessment if they meet the following requirements:			Yes	Short Circuit Analysis	We do not currently have past studies for short circuit.	Doug Bowman	Investigate the use past studies performed by individual members	
TPL-001-2	R2.6.1.	For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.			Yes	Short Circuit Analysis	Short Circuit analysis has never been performed	Doug Bowman		
TPL-001-2	R2.6.2.	For steady state, short circuit, or Stability analysis no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.			Yes	Short Circuit Analysis	Short Circuit analysis has never been performed	Doug Bowman		
TPL-001-2	R.2.7.	For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action plan(s) addressing how the performance requirements will be met. Revisions to the Corrective action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:			Yes	Stability & Short Circuit Analysis	Addition of a Near Term and a Long-Term Study Model Assessment for Stability an Short Circuit Analysis	Scott Jordan & Doug Bowman		

Standard Number	Req. #	Text of Requirement	Violation Risk Factor	Time Horizon	Gap Yes/No	Possible Evidence	Gap Description	Mitigation Planner	Remarks	Resources
TPL-001-2	R2.7.1.	List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions: • Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment. • Installation, modification, or removal of Protection Systems or Special Protection Systems. • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. • Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations. • Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan. • Use of rate applications, DSM, new technologies, or other initiatives.			Yes	Steady State, Short Circuit, & Stability Analysis	The corrective action plans may contain one of the following.	Jason Speer, Doug Bowman, & Scott Jordan		
TPL-001-2	R2.7.2.	Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.			Yes	Short Circuit Analysis	Short Circuit analysis has never been performed	Doug Bowman		
TPL-001-2	R2.7.3.	If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of non-Consequential Load Loss or curtailment of Firm Transmission Service.			Yes	Short Circuit Analysis	Short Circuit analysis has never been performed	Doug Bowman		
TPL-001-2	R2.7.4.	Be reviewed in subsequent annual planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.			Yes	Short Circuit Analysis	Short Circuit analysis has never been performed	Doug Bowman		
TPL-001-2	R2.8.	For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:			Yes	Short Circuit Analysis	Short Circuit analysis has never been performed	Doug Bowman		
TPL-001-2	R2.8.1.	List System deficiencies and the associated actions needed to achieve required System performance.			Yes	Short Circuit Analysis	Short Circuit analysis has never been performed	Doug Bowman		
TPL-001-2	R2.8.2.	Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures			Yes	Short Circuit Analysis	Short Circuit analysis has never been performed	Doug Bowman		
TPL-001-2	***R3.***	***For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirements R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1.***	High	Long-Term Planning	Yes	Steady State Analysis	Year five model and near-term off-peak.	Jason Speer		
TPL-001-2	R3.1.	Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.			No					
TPL-001-2	R3.2.	Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5.			Yes	Steady State Analysis	We do not run the extreme events for the Long Term assessment.	Jason Speer		
TPL-001-2	R3.3.	Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:								
TPL-001-2	R3.3.1.	Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: 1) Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. 2) Tripping of Transmission elements where relay loadability limits are exceeded.			Yes	Steady State Analysis	Generator tripping and relay loadability limits	Jason Speer	Coordinate with SPCWG/ TWG	
TPL-001-2	R3.3.2.	Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.			Yes	Steady State Analysis	VAR control and inductor control	Jason Speer	Check with OPM	

Standard Number	Req. #	Text of Requirement	Violation Risk Factor	Time Horizon	Gap Yes/No	Possible Evidence	Gap Description	Mitigation Planner	Remarks	Resources
TPL-001-2	R3.4.	Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.			No					
TPL-001-2	R3.4.1	The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.			Yes	Steady State Analysis	Tie-lines with surrounding Planning Coordinator and Transmission Planner.	Jason Speer	Include NERC IDC flowgate list in contingency analysis	
TPL-001-2	R3.5.	Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.			Yes	Steady State Analysis	Possible use of POM for studying cascading outage using their new module.	Jason Speer		
TPL-001-2	***R4.***	***For the Stability portion of the Planning Assessment, as described in Requirement R2, parts 2.4 and 2.5, each Transmission Planner, and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.***		Long-Term Planning	Yes	Stability Analysis	Add contingencies and the assessment of a near-term and long term model.	Scott Jordan		
TPL-001-2	R4.1	Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created I Requirement R4, part 4.4.			Yes	Stability Analysis	Add/Modify contingencies list	Scott Jordan		
TPL-001-2	R4.1.1	For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.			Yes	Stability Analysis	Expand current contingency list	Scott Jordan		
TPL-001-2	R4.1.2.	For planning event P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.			Yes	Stability Analysis	Add contingencies to current list	Scott Jordan		
TPL-001-2	R4.1.3	For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.			Yes	Stability Analysis	Add contingencies to current list	Scott Jordan		
TPL-001-2	R4.2.	Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement 4, part 4.5.			No					
TPL-001-2	R4.3.	Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall:								
TPL-001-2	R4.3.1.	Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: 1)Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized. 2)Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage rid ethrough capability. Include in the assessment any assumptions made. 3) Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.			Yes	Stability Analysis	Addition Special Protection Schemes to simulations, add trip generator as necessay to simulations	Scott Jordan	Coordinate with SPCWG/ TWG, explore new stability tools	
TPL-001-2	R4.3.2	Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.			No					
TPL-001-2	R4.4.	Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.	High		No					
TPL-001-2	R4.4.1.	Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.			Yes	Stability Analysis	SPP needs to develop a formal communications process with neighboring utilities and RTOs to address this requirement	Scott Jordan	Include NERC IDC flowgate list in contingency analysis	

Standard Number	Req. #	Text of Requirement	Violation Risk Factor	Time Horizon	Gap Yes/No	Possible Evidence	Gap Description	Mitigation Planner	Remarks	Resources
TPL-001-2	R4.5.	Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified an a list created of those events to be evaluated in Requirement R3, part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) sha be conducted.			No					
TPL-001-2	***R5.***	***Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.***	Severe	Long-Term Planning	Yes	Steady State & Stability Analysis Criteria	Additions of the evaluation of Transient Voltage Response	Jason Speer & Scott Jordan	Include this is SPP's proposed Stability Criteria	
TPL-001-2	***R6.***	***Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.***	Severe	Long-Term Planning	Yes	Stability Criteria	Develop and get approved Stability criteria.	Scott Jordan		
TPL-001-2	***R7.***	***Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.***	Severe	Long-Term Planning	No					
TPL-001-2	***R8.***	***Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment , and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request .***	High	Long-Term Planning	Yes	Co-ordination Process	SPP needs to develop a formal communications process with neighboring utilities and RTOs to address this requirement	Jason Speer, Doug Bowman, & Scott Jordan	Coordinate with ERAG and other Regional Entities	
TPL-001-2	R8.1.	If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	Severe		Yes	Co-ordination Process	This requirement needs to be part o the process for R.4.4.1 and R.8	Jason Speer, Doug Bowman, & Scott Jordan		

2011 Probabilistic Assessment

August 3-4, 2011

Michael O. Odom
modom@spp.org 501.688.8205

SPP Southwest Power Pool

Probabilistic Assessment Background

- Background
  - NERC's Generation and Transmission Reliability Planning Models Task Force (GTRPMTF) recommended the creation of an annual report summarizing a probabilistic assessment of the resource adequacy by area across NERC. The GTRPMTF was disbanded and the Planning Committee has assigned RIS to coordinate the assembly of this report.
  - The Probabilistic Assessment report is voluntary for 2011, but may become mandatory in 2012.

Probabilistic Assessment Objective

- Objective of the pilot report
  - To provide a common set of probabilistic reliability indices and recommend probabilistic based work products and tools that could be used to supplement the NERC's long-term reliability assessments.
  - The Probabilistic Assessment (ProbA) Report is designed to complement the Long-Term Reliability Assessment providing additional probabilistic statistics of Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE). For this 2011 pilot report, the second and fifth year of the *2010 Long-Term Reliability Assessment*—2011 and 2014 results will be calculated.

Probabilistic Assessment Drivers

- "Successful execution of a long-term probabilistic-based reliability assessment is a significant step forward in determining future reliability of the bulk power system in North America." – ERO
- This assessment provides a common set of probabilistic reliability indices and work products, which supplements the NERC Long-Term Reliability Assessment's resource adequacy assessment.
- FERC directs NERC to develop a plan to address capacity and energy in its reliability assessment methodology and a timeline for executing the plan, and submit the plan and timeline as part of the 2011 LTRA.

SPP's Probabilistic Assessment Methodology

- Methodology
  - GridView 6.0, a product of ABB/Ventyx, is the software application used by SPP to perform the computational analysis of the reliability indices
  - GridView uses a Monte Carlo simulation with at least 50 draws to perform the calculation of the reliability indices
  - The load forecast uncertainty is applied to both reporting years assuming normal distribution with 4% standard deviation

SPP's Probabilistic Assessment Modeling

- Modeling
  - Area hourly load profiles have the LTRA peak load forecast values applied
  - Capacity is modeled with the forecasted max capacity values and forced outage rates. The units are removed from service during a scheduled maintenance window. Wind shapes are included as hourly resources.

SPP's Probabilistic Assessment Results

- Results
  - Loss Of Load Hours (LOLH in Hours/Year)
  - Expected Unserved Energy (EUE in MWh/Year)
  - Net Energy for Load (normalized EUE in MWh/Year)
  - *Loss of Load Expectation (LOLE in Hours/Year)
  - Comparison with the 2010 LTRA forecasted data

*LOLE is not required for this report, but will be calculated to meet SPP criteria

SPP's Probabilistic Assessment Timeline

- Timeline
  - Draft report will be completed and submitted by October 3, 2011.
  - Final report will be completed and submitted February 2012.

SPP 9

Reliability Standards Update

TWG Meeting
August 3, 2011

Omaha, NE

Jonathan Hayes
jhayes@spp.org · 501-614-3509

SPP Southwest Power Pool

Strengthen SPP's involvement with NERC standard development

- Improve awareness of standards under development
- Provide SPP membership a louder voice in the development process
- Reduce compliance violations by
  - increasing awareness of upcoming changes
  - improving reliability standards
- Add value for SPP members

SPP 2

SPP Reliability Standards Update

- What have we been doing?
- Where are we going?

Draft Standards Review (WebEx)

- Monitor Reliability Standards out for comment
  - White papers, SARs, CANs, FERC orders, reports, etc…
- Schedule WebEx/conference call
  - Announcement Notices Sent to
    - compliance distribution list
    - interested working groups / task forces
    - internal subject matter experts (SMEs)
  - Discuss the document and suggest improvements
  - Submit comments to Standard Drafting Teams, NERC, FERC, etc…

Draft Standards Reviewed

- In the last 6 months
  - 2006-02 Assess Transmission Future Needs (TPL-001-02)
  - 2007-03 Real-time Operations (TOP-001-2, TOP-002-3, TOP-003-2)
  - 2007-09 Generator Verification (Part 1: MOD-025-2, MOD-027-1, PRC-019-1 and Part 2: MOD-026-1, PRC-024-1)
  - 2007-17 Protection System Maintenance & Testing (PRC-005-2)
  - 2009-01 Disturbance and Sabotage Reporting (EOP-004-2)
  - 2009-02 Real time Reliability Monitoring and Analysis Capabilities (Whitepaper)
  - 2009-06 Facility Ratings (FAC-008-3)
  - 2010-05.1 Protection System Misoperation (PRC-004-3)

SPP 5

Draft Standards Reviewed cont….

- 2010-07 Generator Requirements at the Transmission Interface (FAC-001-1, FAC-003-3, FAC-003-X)
- 2010-17 BES Definition, Technical Principles, Rules of Procedure
- NERC Rules of Procedure, Appendix 4B, Appendix 4C
- Generating Availability Data System (GADS) Mandatory Reporting of Conventional Generator Data
- Cauley/SPP Board Visit (talking points)
- CAN-0024 CIP-002 thru CIP-009
- CAN-0026 TOP-006
- CAN-0030 Attestations
- FERC ERO Interpretation of Transmission
- FERC Frequency Response Compensation NOPR

SPP 6

Coordination with Working Groups

- SPP
  - GWG
  - ORWG
  - SPCWG
  - TWG
- NERC
  - Standards Committee
  - Planning Committee
  - Resources Subcommittee
  - Transmission Issues Subcommittee
  - Operating Reliability Subcommittee
  - IRC/Standards Review Committee

SPP 7

NERC Standard Drafting Teams

- Generator Relay Loadability
- Reliability Coordination (Project 2006-06)
- BES Definition (Project 2010-17 Observer)

SPP 8

Where are we going?

- NERC 'Top 12'
  - Assess Transmission Future Needs (2006-02)
  - Reliability Coordination (2006-06)
  - Operating Personnel Communicating Protocols (2007-02)
  - Real-time Transmission Operations (2007-03)
  - System Protection Coordination (2007-06)
  - Vegetation Management (2007-07)
  - Generator Verification (2007-09)

SPP 9

Where are we going?

- NERC 'Top 12' (continued)
  - Frequency Response (2007-12)
  - Protection System Maintenance & Testing (2007-17)
  - Cyber Security Order 706 (2008-06)
  - Disturbance & Sabotage Reporting (2009-01)
  - Phase 1 of Protection Systems: Misoperations (2010-05.1)
  - Generator Requirements at the Transmission Interface (2010-07)
  - Definition of BES (2010-17)

SPP 10

NERC Current Activities

- 30 SARs / Standards in development not posted for comment
- 8 interpretations under development not posted for comment
- 1 project up for comment (2 standards)
- 2 projects up for ballot (5 standards)
- 26 Reliability Standards filed pending Regulatory approval
- 18 projects pending Regulatory filing

SPP 11

Moving forward

- Improve awareness of standards under development
- Provide SPP membership a louder voice in the development process
- Improve reliability standards
- Add value for SPP members

SPP 12

To accomplish this

- Need your feedback:
  - What can we do to improve our current process
  - How can we make it better for you
  - What are we doing right
  - What are we doing wrong

SPP 13

Send your comments to:

- Robert Rhodes
  - rrhodes@spp.org
  - 501-614-3241
- Jonathan Hayes
  - jhayes@spp.org
  - 501-614-3509

SPP 14

TPL-001-2

- Recirculation ballot ended 7/22/2011
  - Quorum 94.33 %
  - Approval 75.37 %
- Next steps
  - Presented to NERC Board of Trustees for adoption and filed with regulatory authorities.
  - ETA BOT August 4th and three to 4 weeks later for FERC filing.
  - http://www.nerc.com/docs/standards/sar/atfnsdt_recirc_ballot_tpl_001_2_clean_20110711.pdf

Project Cost Task Force Overview

Transmission Working Group

Terri Gallup, PCTF Chair

August 4, 2011

Southwest Power Pool

RSC Motions (Oct 2010)

- MOTION 1: RSC recommends that SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded.
- MOTION 2: RSC recommends that SPP review the Novation Process and report to the RSC by April 2011.
- MOTION 3: RSC recommends that SPP consider establishing design and construction standards for transmission projects at 200 kV and above that are regionally funded.
- MOTION 4: SPP evaluate how cost estimates are established for transmission projects before Cost Benefit Analysis are performed.
- MOTION 5: CAWG to study various methods on how costs that exceed some standard can be addressed with different cost allocation mechanisms and recommend strategies to RSC.

SPP 2

SPCTF Recommendations

- Standardized estimation methodologies
  - Consistent estimation principles
  - Standardized cost estimate template
  - Define allowable cost variance
- Tiered approach to cost estimating
- Create a Study Estimate Design Guide for Study Estimates
- PCWG to review any deviations from Study Estimate Design Guide
  - If estimate deviates from allowable variance, NTC/CNTC could be modified or withdrawn

SPP 3

Stages of Cost Estimation

1) Conceptual Estimate **(Staff)**
   - prepared by SPP from historical data
   - used for screening purposes only
2) Study Estimate **(DTO)**
   - submitted by DTO if project passes Conceptual screening and requires more refined estimate
3) NTC Project Estimate (NPE)/CNTC Project Estimate (CPE) **(DTO)**
   - submitted by DTO in response to CNTC/NTC issuance
   - established as baseline for project cost variance
4) Design/Construction Estimate **(DTO)**
   - submitted by DTO in quarterly tracking process for cost estimates as engineering and construction for project is underway/completed

SPP 4

Cost Estimate Stage Definition

Estimate Name	Stage		Level of Project Scope Definition	End Usage	Precision Bandwidth
	Projects > 100 kV & > $20 Million	All other BOD Approved Projects			
Conceptual	1	1	0% to 10%	Concept screening for ITP20/ITP10	-50% to + 100%
Study	2	2	10% to 20%	Study of feasibility and plan development for ITP10/ITPNT	-30% to +30%
	CNTC Issued	*NTC Issued*			
CNTC Project (CPE)	3	N/A	20% to 40%	Final baseline (CNTC)	-20% to +20%
	NTC Issued				
NTC Project (NPE)	N/A	3	20% to 40%	Final baseline (NTC)	-20% to +20%
Design & Construction	4	4	40% to 100%	Design after NTC issued and build the project	-20% to +20%

SPP 5

PCTF Process Improvements

- Standardized Cost Estimate Reporting Template (SCERT)
  - used for all cost estimates
  - used for quarterly reporting
- Project Cost Working Group (PCWG)
  - detail its role in project tracking process for Applicable Projects
- Conditional Notification to Construct (CNTC)
  - projects > $20 Million and > 100 kV
- Establish Project Estimate baseline
  - CNTC Project Estimate (CPE)
  - NTC Project Estimate (NPE)

SPP 6

PCTF Process Improvements

Project Cost Working Group (PCWG)

- Review whether an Applicable Project that has experienced a cost variance that exceeds a specified bandwidth is reasonable, and to provide a recommendation to SPP
- Applicable Project - regionally funded project (100 kV or >) as a result of an SPP process with cost estimates greater than $20 million
  - May consist of individual cost estimate(s) provided by more than one DTO that sum up to the total Applicable Project cost estimate
  - Each DTO will be held accountable for its portion of the Applicable Project cost estimate

SPP 7

PCTF Process Improvements

DTO will notify SPP if an Applicable Project:

- Deviates *or is expected to deviate* +/- 10% from its established baseline cost
  - SPP staff will notify PCWG
  - PCWG may require the DTO to provide monthly project tracking data via SCERT
- Deviates *or is expected to deviate* +/-20% from its established baseline cost
  - DTO will provide detailed cost variances via updated SCERT with comments and explanations regarding the variances

SPP 8

PCTF Process Improvements

Project Cost Working Group (PCWG)

- Will oversee a quarterly report to be submitted to the MOPC, RSC, and BOD prior to their quarterly meetings
- Will notify MOPC if a trend is developing in cost estimates deviating from the Study Estimate Design Guide
  - MOPC will then determine if a review of the Guide is required
- Will receive the updated scope and SCERT, project tracking data updates, any comments from the DTO related to cost estimate variances, and any applicable input from SPP staff
  - DTO's comments should include relevant information regarding any sunk costs, an explanation for the cost estimate variances, and comments as to why the project should or should not continue forward

SPP 9

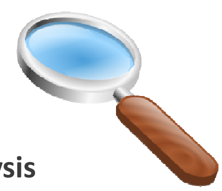
PCTF Process Improvements

- PCWG's recommendations to the MOPC and BOD may include any of the following:
  - Accept the cost deviation as reasonable and acceptable and reset the baseline used to evaluate future cost deviations
  - Identify all or a portion of costs related to the variances and recommend changes to the NTC that would reduce the cost or avoid issues that may be causing the increase
  - Suspend all future expenditures on the project while SPP restudies the project to determine appropriate changes to the NTC or withdrawal of the NTC

SPP 10

Conditional Notification To Construct (CNTC)

- Projects within the financial commitment window
  - Study Estimate > than $20 Million and > 100 kV
- Additional time and cost recovery for DTO to refine estimate
- SPP re-evaluates project if CNTC Project Estimate (CPE) outside accepted bandwidth
- NTC issued
  - Cost variance is acceptable
  - BOD approves the refined cost analysis



SPP 11

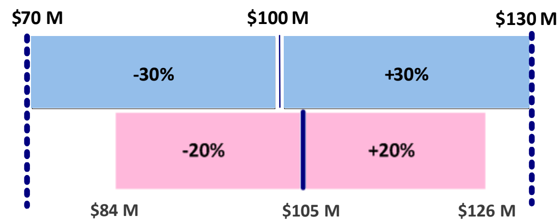
CPE Variance

- If the CPE variance bandwidth exceeds the variance bandwidth of the Study Estimate, SPP staff will re-evaluate this project using the new cost estimate data, and will make a recommendation to the BOD at its next scheduled quarterly meeting
- SPP staff's recommendation could be, but is not limited to, one of the following actions:
  - Accept the cost variance and approve the project as is
  - Modify the existing project
  - Replace the project with an alternative solution
  - Cancel the project

SPP 12

CPE Evaluation Illustrations

Study Estimate: $100 Million



CNTC Project Estimate: $105 Million

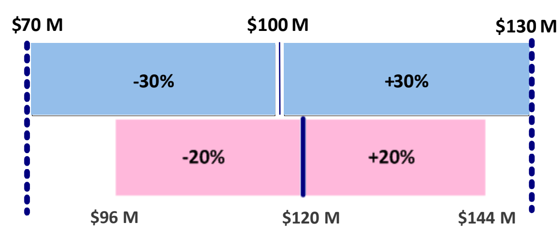
Action: SPP Issues NTC to DTO

If the +/-20% precision bandwidth of the project's CPE is within the accepted range, an NTC will automatically be issued

SPP 13

CPE Evaluation Illustrations

Study Estimate: $100 Million



CNTC Project Estimate: $120 Million

Action: SPP Re-evaluation and BOD Review

If the +/-20% precision bandwidth of the project's CPE is outside the accepted range, SPP Staff will re-evaluate the project and submit updated analysis to BOD for review

SPP 14

Reference Documents for Details

- PCTF White Paper
- PCWG Charter
- DBP&PCTF Study Estimate Design Guide

PROJECT COST TASK FORCE WHITEPAPER

July 19, 2011

Southwest Power Pool

Table of Contents

Introduction......3

RSC Motion 1......3

Problem Summary......3

RSC Motion 4......3

Problem Summary......4

Project Tracking Current Process......4

PCTF Recommendations......4

Standardized Cost Estimate Reporting Template......5

Conditional Notification to Construct......5

Project Tracking Enhancements......6

Project Specification and Cost Estimation Process......7

PCWG Process......15

Appendix A......17

Appendix B......18

Introduction

The Markets and Operations Policy Committee (MOPC) formed the Project Cost Task Force (PCTF) to address the SPP Regional State Committee (RSC) Motions 1 and 4 from their October 25, 2010 meeting. This document provides the recommendations that have been jointly developed by the PCTF, SPP staff, and interested stakeholders to address these Motions.

RSC Motion 1

RSC recommends that SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded.

Problem Summary

The issue of increases in transmission project cost estimates is a result of increased project cost estimates provided by Designated Transmission Owners (DTO) in response to their respective Notification To Construct (NTC) letters for some of the Priority Projects approved by the Board of Directors (BOD) in April 2010. This issue is a product of the increased openness and transparency of the SPP planning processes and concern due to the new Highway/Byway regional cost allocation. In the past, transmission cost estimates tended to remain internal to each member utility, subject only to the utility's internal review processes and any applicable obligations to its regulatory authorities.

With the implementation of SPP's Highway/Byway cost allocation methodology, additional scrutiny is warranted in reviewing changes to regionally funded project cost estimates for projects that were a result of an SPP process and that have cost estimates greater than $20 million (Applicable Projects). An Applicable Project may consist of individual cost estimate(s) provided by more than one DTO that sum up to the total Applicable Project cost estimate. Each DTO will be held accountable for its portion of the Applicable Project cost estimate. This document describes the PCTF and SPP staff proposed process.

RSC Motion 4

SPP evaluate how cost estimates are established for transmission projects before Cost Benefit Analyses are performed.

Problem Summary

Current review of transmission project cost estimates appears to be inadequate, resulting in movement to a more rigorous cost review process that will lead to more transparency of the cost components and assumptions contained within a cost estimate.

The PCTF and SPP staff were charged with creating a standardized and transparent method for the development of transmission project cost estimates associated with Applicable Projects. These cost estimates should be refined as projects move from a conceptual estimate to the design/construction phases of an Applicable Project. The PCTF and SPP staff have proposed a continuous tracking and reporting process that reflects updates that will have increasingly higher levels of accuracy and certainty as the project moves from a conceptual cost estimate stage to the completion of the project.

Project Tracking - Current Process

When SPP issues an NTC for an approved project, it is entered into the Project Tracking process. For an NTC associated with SPP approved Project(s), the DTOs currently have 90 days to respond to the NTC committing to a project(s) as specified in the NTC or proposing a different project schedule or project specifications.

The DTO is required to submit quarterly updates of cost estimates and the expected in-service date. These updates are incorporated into a quarterly report that is submitted to the BOD/Members Committee, the MOPC, and the RSC. In accordance with the guidelines provided in the SPP Open Access Transmission Tariff (OATT) Business Practices document BP 1.15 - Notification to Construct, cost estimates that have increased by more than 20% since the previous estimate require the DTO to submit justification for the variance.

PCTF Recommendations

The PCTF recommends multiple enhancements to the tracking and the cost estimate processes for projects upon which SPP will perform cost benefit analyses.

Revised project tracking enhancements are proposed to the current project tracking process for the DTO to provide a detailed explanation of changes to the study estimate to timely recognize Applicable Projects that are nearing or are already outside stated bandwidths.

To increase the transparency related to modifications of cost estimates for projects after BOD approval and issuance of an NTC to a DTO, a defined cost estimate process is proposed to be used for Applicable Projects. The PCTF also recommends implementing a mechanism for a new working group to review whether a project that has experienced a cost variance that exceeds a specified bandwidth is reasonable, and to provide a recommendation to SPP with the working group findings. SPP will determine whether the project should be reevaluated for construction, with the BOD making a final determination regarding the status of the project under review.

Standardized Cost Estimate Reporting Template

The PCTF recommends the development and implementation of a Standardized Cost Estimate Reporting Template (SCERT) that will be utilized for all approved project cost estimates and applicable monthly/quarterly updates. The PCTF developed the SCERT by assessing the appropriate information to be provided in response to the SPP Project Tracking inquiries. The objectives of the SCERT are to:

a. Provide a consistent format among all estimates
b. Facilitate the Project Tracking process
c. Ensure the required level of detail is provided
d. Facilitate the transition of a completed project into the proper Annual Transmission Revenue Requirement (ATRR) recovery process through SPP's OATT

The SCERT includes: (i) estimated/actual expenditures spent to date; (ii) estimate at completion; (iii) projected in-service date; (iv) direct and indirect costs; (v) AFUDC estimates and if project has CWIP in rate base; and (vi) proposed route map. An example SCERT is included in Appendix A.

Conditional Notification to Construct

The PCTF recommends the introduction of a Conditional Notification To Construct (CNTC) to be issued for Applicable Projects 100 kV and above that have been approved by the SPP Board of Directors (BOD). The purpose of the CNTC is to provide the DTO(s) additional time to perform detailed engineering within a stated timeframe to refine its study estimate for further SPP analysis to determine if the project should proceed with an NTC for actual construction.

The CNTC is not an authorization for the DTO(s) to order materials or begin construction on the project, but rather is an initiative to the DTO(s) to perform any cost estimate analysis not previously done to improve the accuracy of the study estimate such that the DTO(s) will be within a +/- 20% precision bandwidth. The DTO will provide to SPP an estimate of the costs required to respond to CNTC.

The PCTF recommends the DTO(s) should be fully compensated (without ROE) for costs incurred to prepare the refined study estimate for projects that SPP determines will not proceed to construction.

Project Tracking Enhancements

To make the Project Tracking process more rigorous, the PCTF proposes several enhancements that should be considered for implementation after an NTC or CNTC is issued.

For Applicable Projects 100 kV and above that have been approved by the BOD and issued a CNTC:

1. If the DTO accepts the CNTC, it shall provide SPP with a CNTC Project Estimate (CPE) as described in Stage 3 of the proposed process (see Project Specification and Cost Estimation Process below).

2. If the CPE variance bandwidth of -20% to +20% does not exceed the study cost estimate variance bandwidth of -30% to +30%, the project's cost variance will be deemed acceptable and will be immediately issued an NTC by SPP staff. This will be the authorization for the DTO to proceed with the project.

3. If the CPE variance bandwidth exceeds the variance bandwidth of the study estimate, SPP staff will re-evaluate this project using the new cost estimate data, and will make a recommendation to the BOD at its next scheduled quarterly meeting. SPP staff's recommendation could be but is not limited to one of the following actions:

    a. Accept the cost variance and approve the project as is
    b. Modify the existing project
    c. Replace the project with an alternative solution
    d. Cancel the project

4. The study estimate received from the DTO for these projects will be used as the initial baseline for measuring final project approval.

5. If the cost variation of the CPE is accepted by the BOD, the CPE will be used as a final baseline for reporting all cost estimate changes during the Project Tracking process and will be the basis for determining project variance.

For all other projects approved by BOD and issued an NTC:

1. If the DTO accepts the NTC, it shall respond as prescribed in the NTC letter and provide SPP with a refined study cost estimate. This estimate is referred to as the NTC Project Estimate (NPE).

2. The NPE received from the DTO for these projects will be used as the final baseline for reporting all cost estimate changes during the Project Tracking process and will be the basis for determining project variance.

For all Applicable Projects with an approved NPE:

1. SPP's Project Tracking process should be enhanced to require DTOs of all Applicable Projects with an approved NPE to submit Project Tracking updates to SPP staff on a quarterly basis, unless the bandwidth is exceeded as denoted in 1.(a) or 1.(b) below, in which case the DTO will notify SPP immediately with the information as follows:

    a. If an Applicable Project deviates or is expected to deviate +/-10% from its established baseline cost, the DTO will immediately notify SPP staff detailing the cost variances with an updated SCERT with comments on the variances. SPP staff will provide notification to the Project Cost Working Group (PCWG) with no corrective action expected. SPP staff will monitor these projects and take appropriate action if necessary.
    b. If an Applicable Project deviates or is expected to deviate +/-20% from its established baseline cost, the DTO will immediately notify SPP staff detailing the cost variances with an updated SCERT with comments and explanations regarding the variances. SPP staff will provide the updated information to the PCWG. The PCWG will review and provide recommendations to the MOPC and BOD. The PCWG will provide an update to the RSC. The DTO will be required to provide monthly updates to SPP staff until BOD action is taken.

2. At least quarterly, SPP will submit a Project Tracking report to the PCWG detailing all project cost estimate changes outside the established project variance bandwidth.

Project Specification and Cost Estimation Process

The PCTF recommends a tiered approach for project cost estimates based on the level of project definition that is known while also considering an appropriate level of risk valuation. These stages are defined as:

- The **Conceptual Estimate** is the estimate prepared by SPP staff based on historical cost information in an SPP database and updated information provided by the DTO(s). It is to be used as a screening tool to determine if a project is cost-effective and should or should not be pursued in meeting a determined system need. This estimate would not attempt to address detailed environmental, geography, terrain or other issues.

- The **Study Estimate** is the estimate prepared by the DTO(s) for projects that pass the Conceptual Estimate screening process and require a more refined cost estimate for project approval.

- The **CNTC Project Estimate (CPE)** is the estimate prepared by the DTO(s) for projects after the receipt of a CNTC. This estimate will include any cost estimate analysis not previously done to improve the accuracy of the Study Estimate, but before any construction investment is made by the DTO(s).

- The **NTC Project Estimate (NPE)** is provided by the DTO after receipt of an NTC for a non-Applicable Project; it includes any additional cost information known at the time the DTO is required to provide its response to the SPP.

- **Design and Construction Estimates** are provided by the DTO to SPP after the DTO engineering and construction are being completed, including any environmental, routing or siting requirements, and that has a known route. This would include but not be limited to any known material and labor costs. This cost estimate will also include any known condemnation costs.

The Cost Estimate Stage Definition table below lists the four stages of the project estimating process. Each of these stages must have more refined requirements for the accuracy of cost estimates and detail of data. The bandwidth for estimate accuracy reduces as the scope definition detail increases.

Estimate Name*	Stage		Level of Project Scope Definition	End Usage	Precision Bandwidth
	Projects > 100 kV & > $20 Million	All other BOD Approved Projects			
Conceptual	1	1	0% to 10%	Concept screening for ITP20/ITP10	-50% to + 100%
Study	2	2	10% to 20%	Study of feasibility and plan development for ITP10/ITPNT	-30% to +30%
	CNTC Issued	*NTC Issued*			
CNTC Project (CPE)	3	N/A	20% to 40%	Final baseline (CNTC)**	-20% to +20%
	NTC Issued				
NTC Project (NPE)	N/A	3	20% to 40%	Final baseline (NTC)**	-20% to +20%
Design & Construction	4	4	40% to 100%	Design after NTC issued and build the project	-20% to +20%***

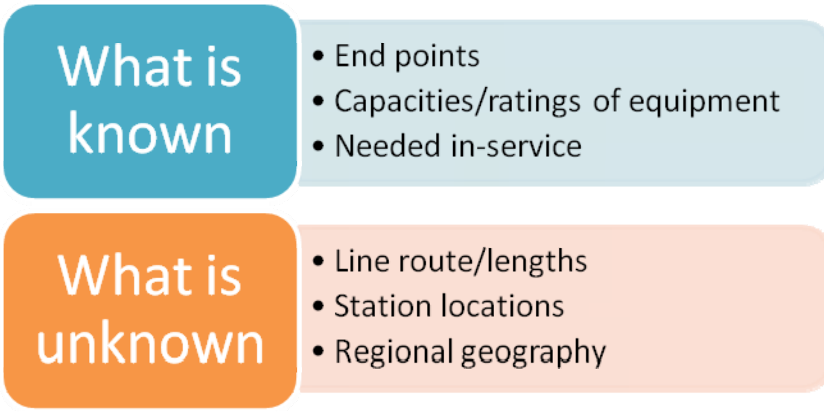
** The Conceptual Estimate will be prepared by SPP. All subsequent estimates will be prepared by the DTO(s).*
***BOD approval required to reset the baseline.*
****Actual cost is expected to be within +/-20% of final baseline estimate.*

Table 1: Cost Estimate Stage Definition

The PCTF recommends that DTOs develop consistent cost estimates through the completion of a SCERT for similar information to be included in a cost estimate as well as assumptions used by the DTO to develop the Study Estimate. For the Study phase estimate, all DTOs shall base those estimates relative to Study Estimate Design Guide.

The sections below describe each Stage of the Cost Estimation process in more detail:

Conceptual Estimate Stage



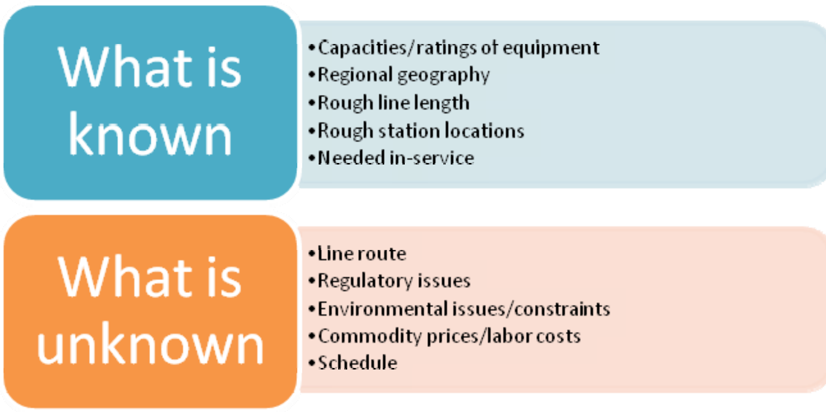
Knowns and unknowns are meant to be illustrative

In this first stage, SPP staff will develop the initial project scopes and Conceptual Estimates using a generic cost estimate tool (database platform) that will be developed in conjunction with the Transmission Owners[1]. The estimating tool will include generic SPP historical cost data such as cost per mile for specific voltage levels, substation cost estimates, and cost modifiers for other factors such as different regions, terrain, urban/rural, etc. This allows cost estimates to be developed easily for screening large numbers of potential projects and selecting suitable candidates for further study.

The output of the tool will be a table providing the total cost estimate for each project under consideration, as well as all the supporting information for each. This will provide an easy-to-use reference for the cost estimates and the variations among them. SPP staff, in conjunction with the Transmission Owners, will update the cost data used in the cost estimating tool on an annual basis. To support these updates, SPP staff will provide an aggregate summary of final cost data collected in the Project Tracking process. This will ensure the cost estimate tool is kept up-to-date for Conceptual Estimates and will help refine the tool to reflect actual costs.

[1] Future development

Study Estimate Stage



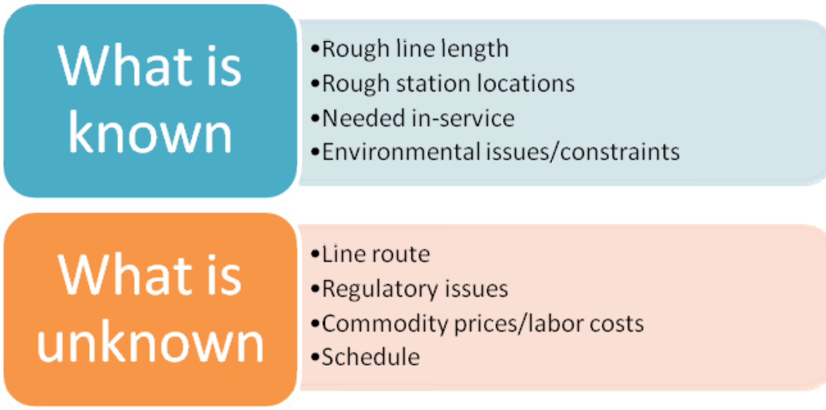
Knowns and unknowns are meant to be illustrative

Stage 2 begins after the initial project screening is completed and the list of potential projects has been narrowed to those most likely to be selected. SPP and incumbent DTO for each project must review and refine the project scope and provide study-level cost estimates for each alternative project.

The Study Estimate is the first detailed estimate the DTOs will be required to submit. For this estimate, DTOs will base assumptions relative to the Study Estimate Design Guide. There are still a large number of unknowns at this point in the planning process and the project scope should identify those unknowns and the risks associated with them.

The final project cost is expected to be within a -30% to + 30% variance from Study Estimate.

CNTC Project Estimate Stage



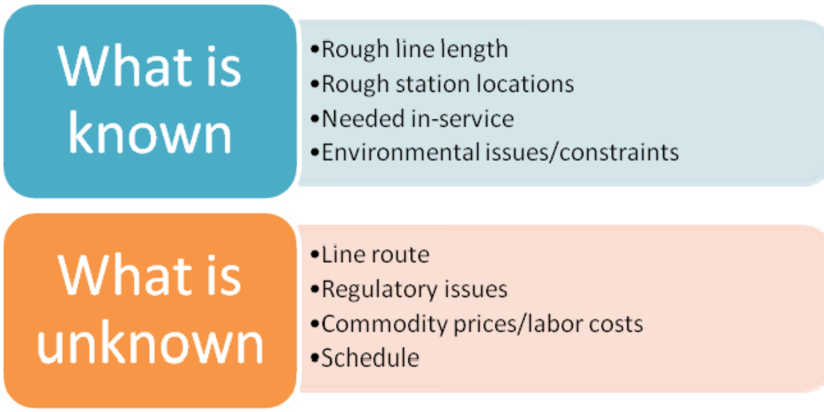
Knowns and unknowns are meant to be illustrative

For Applicable Projects 100 kV and above, the DTO’s time to submit an updated cost estimate to SPP, referred to as the CNTC Project Estimate (CPE), will be extended to allow the DTO the opportunity to perform cost estimate analysis not previously done to improve the accuracy of the Study Estimate.

The CPE should be submitted to SPP no later than four months prior to the start of the next applicable ITP process cycle. If the cost variation exceeds the accepted bandwidth, SPP staff will re-evaluate the project with the updated cost data and present this analysis to the BOD, no later than one quarter prior to the start of the next applicable ITP process cycle.

The final project cost is expected to be within a -20% to + 20% variance from the CPE.

NTC Project Estimate Stage

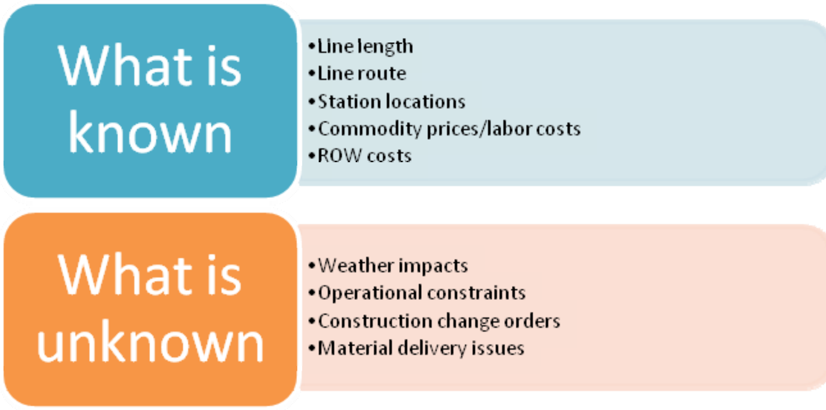


Knowns and unknowns are meant to be illustrative

This stage begins after a non-Applicable Project has been issued an NTC. The DTO has 90 days to respond to the NTC by committing to a project as specified in the NTC or proposing a different project schedule or project specifications. If the DTO accepts the NTC, it shall respond as prescribed in the SPP NTC letter and provide SPP with a refined study scope and cost estimate. This estimate will be referred to as the NTC Project Estimate (NPE). The NPE will cover the period between accepting the NTC and the start of project design.

The final project cost is expected to be within a -20% to + 20% variance from the NPE.

Design and Construction Estimate Stage



Knowns and unknowns are meant to be illustrative

This stage covers the period between starting design engineering to the final project closeout and submittal of actual project costs to SPP through the Project Tracking process. All line-item differences between the estimate being used as a baseline and these updated estimates must be accompanied by a detailed explanation from the DTO.

The final project cost is expected to be within a -20% to + 20% variance from the applicable CPE or NPE.

PCWG Process

The PCTF proposes that SPP stage the implementation of the process proposed for PCWG to initially apply to approved Applicable Projects 300 kV and above, and after the process is refined and working well to include approved Applicable Projects 100 kV and above.

The DTO shall immediately provide data and information to SPPprojecttracking@spp.org for any Applicable Project that deviates or is expected to deviate +/- 10% from its established baseline cost. SPP staff will then notify the PCWG. The PCWG may require the DTO to provide a monthly project tracking data.

If an Applicable Project deviates or is expected to deviate +/-20% from its established baseline cost, the DTO will immediately notify SPP staff detailing the cost variances with an updated SCERT with comments and explanations regarding the variances. The PCWG will oversee a quarterly report to be submitted to the MOPC, RSC, and BOD prior to their quarterly meetings. The PCWG will notify MOPC if a trend is developing in cost estimates deviating from the Study Estimate Design Guide. The MOPC will then determine if a review of the Guide is required.

The PCWG will receive the updated scope and SCERT, project tracking data updates, any comments from the DTO related to cost estimate variances, and any applicable input from SPP staff. The DTO's comments should include relevant information regarding any sunk costs, an explanation for the cost estimate variances, and comments as to why the project should or should not continue forward.

The PCWG's recommendations to the MOPC and BOD may include any of the following:

i. Accept the cost deviation as reasonable and acceptable and reset the baseline used to evaluate future cost deviations.
ii. Identify all or a portion of costs related to the variances and recommend changes to the NTC that would reduce the cost or avoid issues that may be causing the increase.
iii. Suspend all future expenditures on the project while SPP restudies the project to determine appropriate changes to the NTC or possible withdrawal of the NTC.

If the PCWG recommends a restudy and/or changes or revocation of the NTC, the recommendation to the MOPC would follow SPP's existing processes for approval to the BOD. The BOD will make the final determination on whether to restudy and/or change or revoke the NTC.

There are instances when resetting the baseline cost estimate will be prudent, as it would not be reasonable for a project to be flagged automatically for review every month following a cost estimate variance that had been previously reviewed and accepted. The PCWG will recommend to the BOD whether to reset the baseline cost estimate. The BOD will make the final determination on whether to reset the baseline. If a baseline cost estimate is reset, the previous estimates will be retained in the monitoring tool.

Appendix A

Standardized Cost Estimate Reporting Template (SCERT)

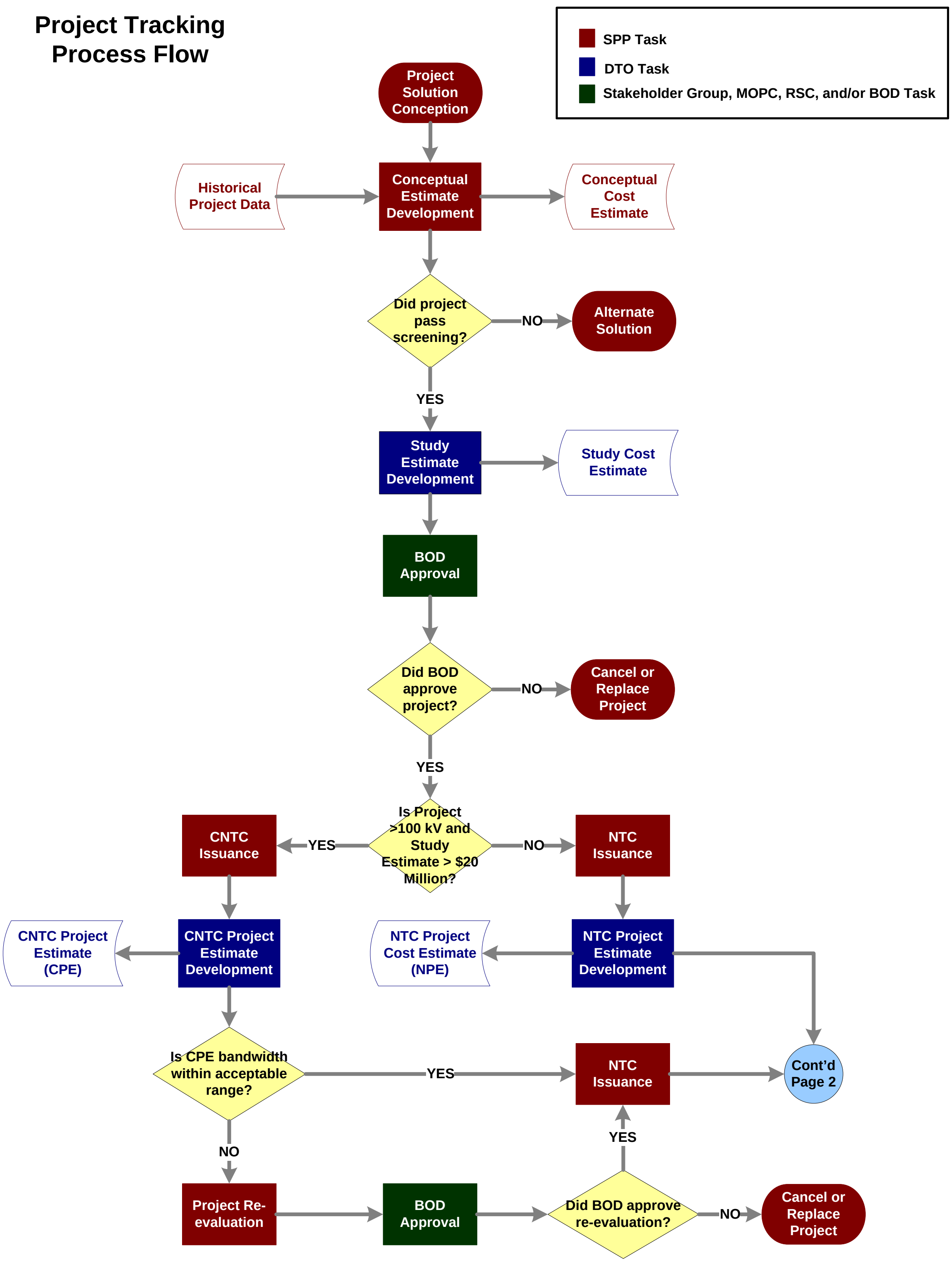
SPP Project Name	
Current Year Dollars	
Loaded Nominal Dollars	
Project ID	
Upgrade ID	
Estimate Provider	
Estimate Creation Date	
Project Scope	
RTO Determined Need Date	
Project Start Date	
In-Service Date	

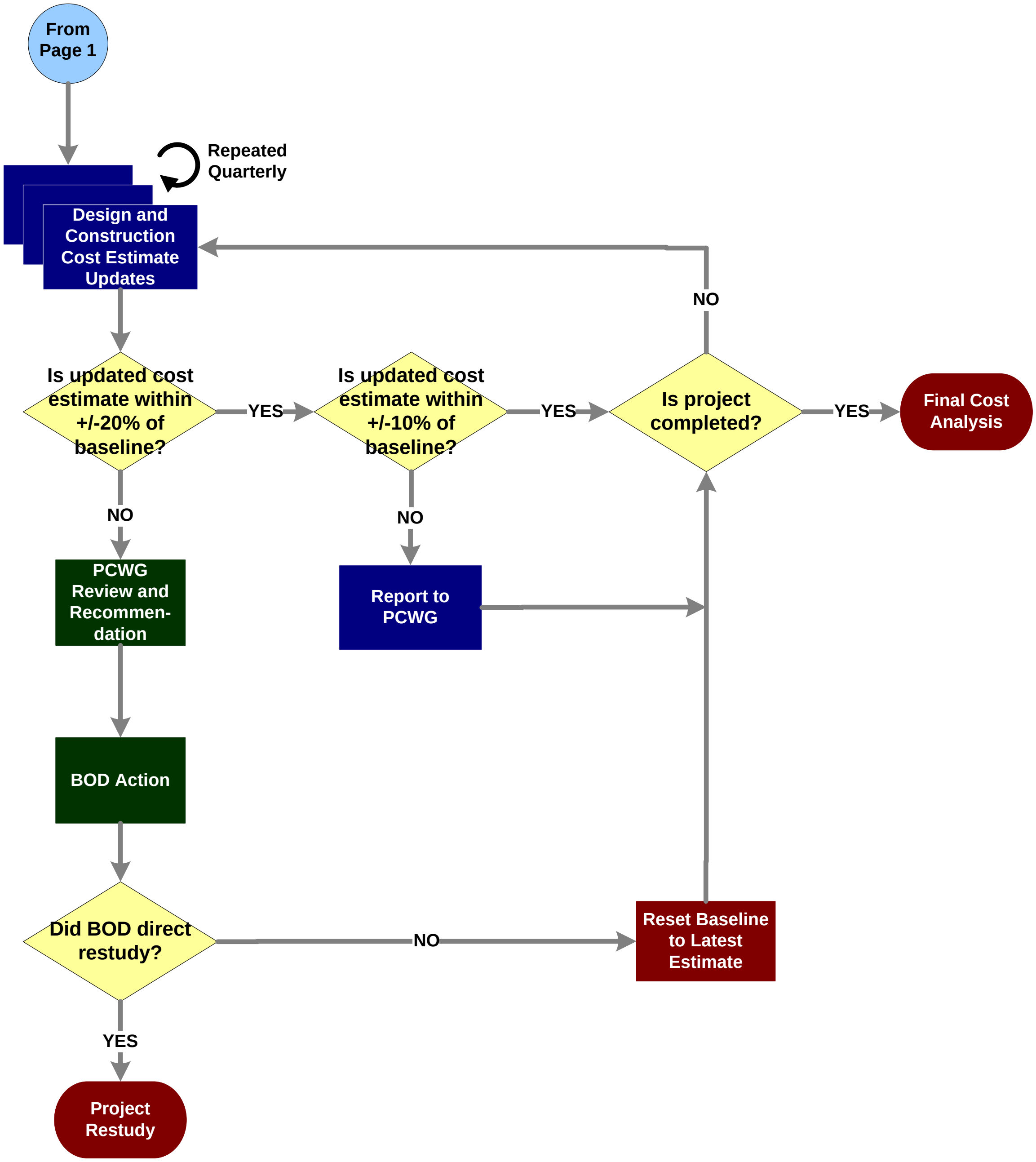
Line Costs	**Loaded Nominal $**
Engineering Labor	
Construction Labor	
Right-of-Way	
Material	
Line Sub-Total	
Station Costs	
Engineering Labor	
Construction Labor	
Site Property Rights	
Material	
Station Sub-Total	
Summary Info	
Line Sub-Total	
Station Sub-Total	
AFUDC	
CWIP (Y/N)	
Contingency	
Total Project Cost Estimate	

Line Assumptions		**Segment 1**	**Segment 2**
	Mileage		
	Number of Circuits		
Shield Wire	Number		
	Type		
	Size		
Conductor	Type		
	Size		
	Rating		
	# Conductors per Phase		
Structure	Configuration		
	Foundation Type		
	Material		
	NESC Assumptions		
	Dead Ends		
	Tangents		
	Underbuild		

Station Assumptions		**Station 1**	**Station 2**
	Location		
Transformers	Quantity		
	Size		
Breaker Scheme	Quantity		
	Size		

Appendix B


Project Tracking Process Flow
SPP Task
DTO Task
Stakeholder Group, MOPC, RSC, and/or BOD Task
Project Solution Conception
Historical Project Data
Conceptual Estimate Development
Conceptual Cost Estimate
Did project pass screening?
NO
Alternate Solution
YES
Study Estimate Development
Study Cost Estimate
BOD Approval
Did BOD approve project?
NO
Cancel or Replace Project
YES
Is Project >100 kV and Study Estimate > $20 Million?
YES
CNTC Issuance
NO
NTC Issuance
CNTC Project Estimate (CPE)
CNTC Project Estimate Development
NTC Project Cost Estimate (NPE)
NTC Project Estimate Development
Is CPE bandwidth within acceptable range?
YES
NTC Issuance
Cont'd Page 2
NO
YES
Project Re-evaluation
BOD Approval
Did BOD approve re-evaluation?
NO
Cancel or Replace Project


From Page 1
Repeated Quarterly
Design and Construction Cost Estimate Updates
Is updated cost estimate within +/-20% of baseline?
YES
NO
PCWG Review and Recommen-dation
BOD Action
Did BOD direct restudy?
YES
Project Restudy
NO
Is updated cost estimate within +/-10% of baseline?
YES
NO
Report to PCWG
Is project completed?
YES
NO
Final Cost Analysis
Reset Baseline to Latest Estimate

Introduction

Applicability

This document outlines the Design Best Practices and Performance Criteria (DBP&PC) to be used by the Transmission Owner (TO) when developing Study Estimates for the SPP footprint projects rated at voltages of 100 kV and greater. These DBP&PC have been incorporated into this Study Estimate Design Guide and are intended to promote consistency in TO Study Stage estimates.

Recognizing the importance of well defined scopes when developing cost estimates, this document also contains scoping guidelines for the Conceptual and Study estimate phases. These guidelines will promote mutual understanding of the project definition between SPP and the TOs as the project is developed and estimates are prepared for the applicable phase of the potential project.

TO Study Estimate assumptions will be detailed in the Standardized Cost Estimate Reporting Template (SCERT) as used by the SPP project cost tracking process.

Design Best Practices and Performance Criteria

Design Best Practices represent high-level, foundational principles on which sound designs are based. Design Best Practices facilitate the design of transmission facilities in a manner that is compliant with NERC, SPP, and TO requirements; are consistent with Good Utility Practice as defined in the SPP Open Access Transmission Tariff (SPP Tariff)[1]; are consistent with industry standards such as NESC, IEEE, ASCE, CIGRE, and ANSI; and are cost-effective. Although not addressed here, construction and maintenance best practices must be considered during the design phase to optimize these costs and efficiencies.

Performance Criteria further define the engineering and design requirements needed to promote a more uniform cost and reliability structure of the transmission facilities and to ensure that the TOs construct project(s) within the parameters requested by SPP. Flexibility is given such that the TO's historical and current performance criteria, business processes, and operation and maintenance practices are considered. Individual sections within this document contain both Design Best Practices and Performance Criteria.

Scope Management

A well developed and rigorously managed scoping document promotes consistent estimates and helps control costs. It also ensures that the SPP and TO have a clear understanding of the project being reviewed.

[1] The SPP Tariff defines Good Utility Practice as follows: "Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4)."

Design Best Practices & Performance Criteria

Transmission Lines

General

Any criteria established for the design of transmission lines must consider safety, reliability, operability, maintainability, and economic impacts. The NESC contains the basic provisions considered necessary for the safety of utility personnel, utility contractors, and the public. However, the NESC is not intended to be used as a design manual, so Good Utility Practice must also be considered. Where applicable, RUS guidelines should also be considered.

Siting and Routing

The impact of the transmission facility to the surrounding environment should be considered when developing the study estimate. Sensitivity to wetlands, cultural and historical resources, endangered species, archeological sites, existing neighborhoods, and federal lands, are examples that should be considered when siting transmission facilities. The TO must comply with the requirements of all appropriate regulatory agencies during the siting process, and all applicable environmental and regulatory permits must be obtained for the transmission facilities. The TO should describe any known or anticipated environmental issues and associated estimated costs in the Study Estimate, as well as any estimated regulatory siting and permitting costs. Study Estimates will use a default assumption for line mileage that is based upon right angle design absent better assumptions. Where two or more TOs are directed by the SPP to build a project, the TOs shall agree between them how much of the project should be built by each. The TOs will then submit a Study Estimate in accordance with these design best practices.

Electrical Clearances

The clearances of the NESC shall be adhered to in the design of transmission lines. Conductor-to-ground and conductor-to-conductor clearances should include an adequate margin during design to account for tolerances in surveying and construction. Sufficient climbing and working space for NESC and OSHA working clearances should be considered when establishing the geometrical relationships between structure and conductors. Appropriate clearances should be maintained considering NESC requirements, maximum operating temperature, and extreme ice loading. Conductor-to-conductor clearances should account for sag and tension, wire movement variances, and minimum approach distances. Where applicable, dynamic effects (e.g. galloping conductors, ice-drop, etc.), should be considered.

Structure Design Loads

Structures will be designed, at a minimum, to NESC standards and in accordance to the TO's design practices, as appropriate.

Design Load Application

Structures and foundations should be designed to withstand a combination of gravity, wind, ice, conductor tension, construction, and maintenance loads. The following loadings, based on *ASCE Manual of Practice (MOP) 74,* should be considered to help ensure structural integrity under most probable loading combinations. Dynamic loading (e.g. galloping, ice-drop, etc.) of conductors should also be considered.

Loads with All Wires Intact

- NESC requirements
- Extreme wind applied at 90º to the conductor and structure
- Extreme wind applied at 45º to the conductor and structure
- Combined wind and ice loadings
- Extreme ice loading

Unbalanced Loads

- Unbalanced loads as described below should be considered to prevent local and cascading failure. Spacing for cascading should be predicated on TO practices.
    - Longitudinal loads due to unbalanced ice conditions (ice in one span, ice fallen off of adjacent span) with all wires intact
    - Longitudinal loads due to a broken ground wire or one phase position (the phase may consist of multiple sub-conductors)

Construction and Maintenance Loads

- Construction and maintenance loads shall be applied based on the recommendations of *ASCE MOP 74.*
- These loads may be modified based on local TO construction, maintenance, and safety practices.

Structure and Foundation Selection and Design

Structure types may be latticed steel towers or steel, concrete, or wood poles at the TO's discretion. The choice should be based on consideration of structural loading, phase configuration, total estimated installed cost and other economic factors, aesthetic requirements, siting restrictions, and right-of-way requirements.

Structure design should be based on the following as they apply:

- *ASCE Standard No. 10, Design of Latticed Steel Transmission Structures*
- *ASCE Standard No. 48, Design of Steel Transmission Pole Structures*
- *ASCE Publication Guide for the Design and Use of Concrete Poles*
- *ANSI 05-1, Specifications and Dimensions for Wood Poles*
- *IEEE Std. 751, Trial-Use Design Guide for Wood Transmission Structures*

Structures may be supported on concrete piers, grillages, piles, or they may be directly embedded. The method selected shall be based on known or anticipated geotechnical conditions and structure loading.

Insulation Coordination, Shielding, and Grounding

Metallic transmission line structures shall be grounded. Overhead static wires (shield wires) should also be grounded, or a low impulse flashover path to ground should be provided by a spark gap. Individual structure grounds should be coordinated with the structure insulation level and static wire shielding angles (with reference to the phase conductors) to limit momentary operations of the supported circuit(s) to the targeted rate. The coordination of grounding, shielding and insulation should be established considering the effects of span lengths, conductor-to-ground clearances, lightning strike levels, and structure heights.

Rating of Phase Conductors

The maximum operating temperature of phase conductors shall be based on metallurgical capacity (i.e., the maximum temperature the conductor can withstand without incurring damage due to heat) and assuming a reasonable loss of strength.

The conversion to ampacity shall be based on *IEEE Publication No. 738, Standard for Calculating the Current-Temperature of Bare Overhead Conductors,* and SPP Criteria 12.

The TO should select environmental parameters based on its experience and historical and current line rating and operating procedures.

Selection of Phase Conductors

Phase conductors should be selected based on the anticipated power flow of the circuit, metallurgical and mechanical properties, and proper consideration for the effects of the high electric fields.

Minimum Conductor Sizing

The conductor size shall be selected by the TO based on metallurgical (losses, impedance), mechanical, and corona performance. The TO should also consider: electrical system stability (voltage and stability), ampacity, and efficiency effects when selecting conductor size.

The following minimum normal amperage ratings should be considered:

Voltage (kV)	**Amps**
100 - 200	As Specified by SPP
230	1,200
345	3,000
500	3,000
765	4,000

Reconductoring

TOs should consider the application of advanced conductors for reconductoring projects if existing structures are adequate and have sufficient life expectancy to preclude tear down and rebuilds.

Optical Ground Wire

Optical Ground Wire (OPGW) is preferred for all overhead shield wires to provide a communication path for the transmission system. Where there are multiple static wires only one is recommended to be OPGW. Consideration should be given to installing both wires as OPGW at voltages of 345 kV and higher to provide redundancy for protection schemes. Where there is an underground fiber communication path OPGW is not preferred. The size shall be determined based on the anticipated fault currents generating from the terminal substations.

Adequate provisions should be made for OPGW repeater redundancy as well as power supply redundancy at each repeater.

Reactive Compensation

Project cost estimates should include reactive compensation as appropriate. The following table contains the suggested reactive compensation per mile of line:

Voltage (kV)	**Reactive Compensation (MVAR / mi)**
100 - 200	0.1
230	0.3
345	1

Transmission Substations

General

Criteria established for the design of transmission substations must consider safety, reliability, operability, maintainability, and economic impacts. The NESC contains the basic provisions considered necessary for the safety of utility personnel, utility contractors, and the public. However, the NESC is not intended to be used as a design manual, so Good Utility Practice must also be considered. Where applicable, RUS guidelines should also be considered.

Substation Site Selection and Preparation

When selecting the substation site, careful consideration must be given to factors such as line access and right-of-way, vehicular access, topography, geology, grading and drainage, environmental impact, and plans for future growth. Each of these factors can affect not only the initial cost of the facility, but its on-going operation and maintenance costs. Storm water management plans and structures must comply with all federal, state, and local regulations.

Electrical Clearances

The clearances for substation design shall be in accordance with all applicable standards and codes. Vertical clearances to ground shall meet or exceed the NESC requirements. When the exposed conductors are in areas where foot traffic may be present, a margin may be added to the NESC clearance. Substation phase spacing shall meet *IEEE C37.32* and NESC requirements. Sufficient space for OSHA working clearances should be provided when establishing the geometrical relationships between structure and conductors.

Design Load Application

Structures and foundations should be designed for all loads acting on the structure and supported bus or equipment, including forces due to gravity, ice, wind, line tension, fault currents and thermal loads. The following loadings should be considered:

Line Structures and Shield Wire Poles

- NESC requirements
- Extreme wind applied at 90 degrees to the conductor and structure
- Combined wind and ice loadings
- Extreme ice loading

Equipment Structures and Shield Poles without Shield Wires

- Extreme wind, no ice
- Combined wind and ice loadings
- In the above loading cases, wind loads shall be applied separately in three directions (two orthogonal directions and at 45 degrees, if applicable)
- Forces due to line tension, fault currents and thermal loads shall also be considered
- Deflection of structures should be limited such that equipment function or operation is not impaired

Structure and Foundation Selection and Design

Structures may be designed and fabricated from tapered tubular steel members, hollow structural steel shapes, and standard structural steel shapes. The selection of structure type (e.g., lattice, tubular, etc.) should be based on consideration of structural loading, equipment mounting requirements, total estimated installed cost and other economic factors, and aesthetic requirements.

Structure design should be based on the following, as appropriate:

- *ASCE Standard No. 10, Design of Latticed Steel Transmission Structures*
- *ASCE Standard No. 48, Design of Steel Transmission Pole Structures*
- *ASCE Standard No. 113, Substation Structure Design Guide*
- *AISC's Steel Construction Manual*

Structures may be supported on concrete piers, spread footings, slabs on grade, piles, or they may be directly embedded. The method selected shall be based on known or anticipated geotechnical conditions, structure loading, and obstructions (either overhead or below grade).

Grounding

The substation ground grid should be designed in accordance with the latest version of *IEEE Std. 80, Guide for Safety in AC Substation Grounding*. The grid should be designed using the maximum anticipated fault current.

Substation Shielding

All bus and equipment should be protected from direct lightning strikes using an acceptable analysis method such as the *Rolling Sphere Method*. *IEEE Std. 998, Guide for Direct Lightning Stroke Shielding of Substations*, may be consulted for additional information.

Bus Selection and Design

Bus selection and design must take into consideration the electrical load (ampacity) requirements to which the bus will be subjected, in addition to structural loads such as gravity, ice, wind, short circuit forces, and thermal loads. Bus conductor and hardware selection are also critical to acceptable corona performance and the reduction of electromagnetic interference. Allowable span lengths for rigid-bus shall be based on both material strength requirements of the conductor and insulators, as well as acceptable bus deflection limits. Guidelines and recommendations for bus design can be found in *IEEE Std. 605, Guide for Bus Design in Air Insulated Substations.*

Bus Configuration

Substations should be designed to accommodate future expansion of the transmission system (e.g. converting ring bus to a breaker and a half as terminals are added). The following table provides suggested bus configurations.

Voltage (kV)	**Number of Terminals**	**Substation Arrangement**
100 - 499	One or Two	Single Bus
	Three to Six	Ring Bus
	More than Six	Breaker-and-a-half
500/765	One or Two	Single Bus
	Three to Four	Ring Bus
	More than Four	Breaker-and-a-half

Rating of Bus Conductors

The maximum operating temperature of bus conductors should be based on metallurgical capacity (i.e., the maximum temperature the conductor can withstand without incurring damage due to heat) and assuming a reasonable loss of strength.

The conversion to ampacity shall be based on the *IEEE Std. 738, Standard for Calculating the Current-Temperature of Bare Overhead Conductors,* and *IEEE Std. 605, Guide for Bus Design in Air Insulated Substations*. The TO should select environmental parameters based on its experience and historical and current bus rating and operating procedures. Bus conductors should be sized for the maximum anticipated load (current) calculated under various planning conditions and contingencies. The bus should be designed so as to not be the limiting element.

Substation Equipment

Future improvements should be considered when sizing equipment.

Surge protection should be applied, where appropriate, on all line terminals with circuit breakers and considered on all oil-filled electrical equipment in the substation such as transformers, instrument transformers and power PTs.

All substation equipment should be specified such that audible sound levels at the edge of the substation property are appropriate to the facility's location.

Bus and Equipment Insulation Levels

Minimum BIL ratings for substation insulators, power transformer bushings, potential transformer bushings, current transformer bushings, and power PTs are found in the tables below. When placed in areas of heavy contamination (coastal, agricultural, industrial), insulator contamination can be mitigated by using extra-creep insulators, applying special coatings to extra-creep porcelain insulators, and using polymer insulators.

Substation Insulators

Nominal System L-L Voltage (kV)	**BIL (kV Crest)**	**BIL (kV Crest) Heavy Contaminated Environment**
115 - 138	550	650 (Extra Creep)
161	650	750 (Extra Creep)
230	900	900 (Extra Creep)
345	1050	1300 (Extra Creep)
500	1550	1800 (Standard Creep)
765	2050	2050 (Standard Creep)

Power Transformers, Potential Transformers and Current Transformers

Nominal System L-L Voltage (kV)	Power Transformer Winding BIL (kV Crest)	Power PTs (kV Crest)	PT and CT BIL (kV Crest)	Circuit Breaker BIL (kV Crest)
115	450	550	550	550
138	650	650	650	650
161	650	650	650	650
230	825	900	900	900
345	1050	1300	1300	1300
500	1550	N/A	1550 / 1800	1800
765	2050	N/A	2050	2050

Rating Margins for Substation Equipment

Substation equipment shall be rated to carry the anticipated worst-case loading.

Minimum Interrupting Fault Current Levels

Minimum substation design symmetrical fault current ratings can be found in the following table. The fault current capability must exceed expected fault duty.

Voltage (kV)	Interrupting Current Symmetrical (kA)
100 – 345	40
500	50
765	50

Minimum Rating of Terminal Equipment

Minimum ratings of substation terminal equipment should be as follows:

Voltage (kV)	Amps
100 - 200	1,200
230	1,200
345	3,000
500	3,000
765	4,000

Minimum Bus Rating

Minimum ratings of substation bus should be as follows:

Voltage (kV)	Amps
100 - 200	2,000
230	2,000
345	3,000
500	3,000
765	4,000

Substation Service

There should be two sources of AC substation service for preferred and back-up feeds. An acceptable substation service alternative would be to feed the substation service transformers via the tertiary winding of an autotransformer or connect power PTs to the bus. Distribution lines are not preferred as the primary AC source because of reliability concerns, but can be used when other sources are unavailable. If there are no feasible alternatives for a back-up substation service, provision of a generator should be considered.

Control Enclosures

Control enclosures may be designed to be erected on site, or they may be of the modular, prefabricated type. Enclosures may be constructed of steel, block, or other alternative materials, and should be designed and detailed in accordance with the applicable sections of the latest editions of the following:

- *AISC Specification for Structural Steel Buildings*
- *AISI Specification for the Design of Cold-Formed Steel Structural Members*
- *ACI 530/530.1, Building Code Requirements and Specification for Masonry Structures and Related Commentaries*
- *ACI 318, Building Code Requirements for Structural Concrete and Commentary*

Design loads and load combinations should be based on the requirements of the *International Building Code* or as directed by the jurisdiction having authority. Enclosure components shall also be capable of supporting all cable trays and attached equipment such as battery chargers and heat pumps.

Wall and roof insulation should be supplied in accordance with the latest edition of the *International Energy Conservation Code* for the applicable Climate Zone.

Oil Containment

Secondary oil containment should be provided around oil-filled electrical equipment and storage tanks in accordance with the requirements of the United States EPA. More stringent provisions may be adopted to further minimize the collateral damage from violent failures and minimize clean-up costs. Additional design information can be found in IEEE Std. 980, *Guide for Containment and Control of Oil Spills in Substations*

Single Pole Switching / Breakers / Controls

Facilities 500kV and above should consider single pole switching.

Transmission Protection and Control Design

General

Criteria for employing protection and control principles in the design and construction of new substations must adhere to *NERC Reliability Standards* and *SPP Criteria*, as well as individual TO standards.

These guiding principles and best practices center on the following criteria:

- Communication Systems
- Voltage and Current Sensing Devices
- DC Systems
- Primary and Backup Protection Schemes

Communication Systems

Power Line Carrier (PLC) equipment or fiber as the communication medium in pilot protection schemes is recommended to meet the high-speed communication required. PLC equipment is typically used on existing transmission lines greater than five miles in length. Fiber protection schemes should be considered on all new transmission lines being constructed using OPGW. Compatible relays, considering the use of the same manufacturer, should be installed at both ends. Other forms of communication, i.e. microwave or tone, may be considered.

Voltage and Current Sensing Devices

Independent current transformers (CTs) are recommended for primary and backup protection schemes in addition to independent secondary windings of the same voltage source (i.e., CCVTs).

DC Systems

DC systems should be designed in accordance with NERC standards, SPP Criteria, and TO practices.

Primary and Backup Protection Schemes

Primary and backup protection schemes should be required for all lines and be capable of detecting all types of faults on the line. The primary scheme should provide high-speed, simultaneous tripping of all line terminals at speeds that will provide fault clearing times for system stability as defined in *NERC Transmission Planning and Reliability Standards TPL-001 through TPL-004*.

The following criteria should be used to determine if one or two high speed protection systems are needed on a line. While it is possible that the minimum protective relay system and redundancy requirements outlined below could change as *NERC Planning and Reliability Standards* evolve it will be the responsibility of each individual TO to assess the protection systems and make any modifications deemed necessary.

Line Applications:

765 / 500 kV

At least two high speed pilot schemes using a dual battery design and dual direct transfer trip (DTT) using PLC and/or fiber are required. Fiber should be used on all new transmission lines using OPGW, and PLC equipment for existing lines (Mode 1 coupling to all three phases). Where there is an underground fiber communication path OPGW is not preferred. PLC-based protection schemes using directional comparison blocking (DCB) require automatic checkback features to be installed to ensure the communication channel is working properly at all substations.

345 kV

Dual high speed pilot schemes and one direct transfer trip (DTT) using PLC and/or fiber are required. Dual DTT is required if remote breaker failure protection cannot be provided with relay settings. Fiber should be used on all new transmission lines using OPGW and PLC equipment for existing lines. Where there is an underground fiber communication path OPGW is not preferred. Independent PLC communication paths may be required for proper protective relay coordination. PLC-based protection schemes using directional comparison blocking (DCB) require automatic checkback features to be installed to ensure the communication channel is working properly at all substations.

Below 300 kV

A minimum of one high speed pilot scheme using PLC and/or fiber is suggested. Fiber should be used on all new transmission lines using OPGW and PLC equipment for existing lines. Where there is an underground fiber communication path OPGW is not preferred. Dual pilot schemes may be required for proper relay coordination. If dual high speed systems are needed, independent communication channels will be used. PLC-based protection schemes using directional comparison blocking (DCB) require automatic checkback features to be installed to ensure the communication channel is working properly at all substations.

Transformer Applications:

765 / 500 kV

Transformer protection for three (3) single phase banks should be designed considering a dual station battery design, with the protection divided into two systems. The first system should be an overall differential protection scheme. The second system should provide protection for other needs such as internal differential, highside and lowside lead differential, backup overcurrents, sudden pressure and loss of cooling protection. The two protection systems should be separated as much as is practicable.

345 kV - 100 kV

The transformer protection should be divided into two systems, an overall differential protection scheme, and a second system providing protection for other needs such as internal differential, highside and lowside lead differential, backup overcurrents, sudden pressure and loss of cooling protection.

Bus Applications:

765 / 500 kV

Bus protection at this voltage level should be designed considering a dual station battery design. Low impedance bus differential protection should be considered. The protection should be divided into two systems with their own dedicated lockout relay.

345 / 230 kV

Low impedance bus differential protection should be used with the protection divided into two systems with their own dedicated lockout relay.

200 kV and below

Current summation (unrestrained differential) should be typically used in new stations at these voltage levels with the protection scheme divided into two systems with their own dedicated lockout relay. To improve reliability at these voltages, bus one-shot capabilities should be provided when a capacitor bank is installed on the bus and its protection is not accounted for in the bus differential scheme. If bus fault levels are greater than 20kA, then high impedance or low impedance protection solutions must be considered.

Substation Devices

For substation devices, such as capacitor banks, Static VAR Compensators, reactors, appropriate protection systems should be incorporated with due consideration of redundancy and flexibility to facilitate system operations and maintenance.

Phase Measurement Units (PMUs)

PMUs, or Intelligent Electronic Devices (IEDs) capable of providing PMU measurements, should be installed in all new 230 kV and above substations.

SCADA and RTUs

SCADA should be considered for all substations. The capability to retrieve fault records should also be considered.

Scoping Requirements

This section describes the Scoping Requirements to be used by the SPP when developing Conceptual Estimates and the TOs when developing Study Estimates for transmission facilities for the SPP footprint.

Conceptual Estimate Scope Requirements

(Developed by SPP and provided to the TO)

Transmission Line Projects

- Description of project
- Termination points of each transmission line (Point A to Point B)
- Voltage
- Estimated Line length
- Line Ampacity
- Need Date

Transmission Substation Projects

- Description of project
- Voltage
- Need Date
- Transformer requirements

Study Estimate Scope Requirements

(Developed by the TO and provided to SPP)

The Study Estimate Scope document should include the Conceptual Estimate Scope requirements in addition to the information listed below.

Transmission Line Projects

- Structures
  - Structure types - specify lattice structures, poles (wood, steel, concrete, etc.)
  - Number of storm structures, dead ends, running corners, tangents, river crossings and other special structures
  - Foundation information
- Number of circuits

- Conductor size, type and number/phase
- Type of terrain
- Switch requirements
- Legal requirements (e.g. CCN process)
- Geotechnical assumptions
- Special material requirements
- Preliminary line route (rough location when practical)
- Access road requirements
- Design criteria
    - Weather loading
    - Live line maintenance
    - Unbalanced structural loads
- Distribution/Joint Use requirements
- Right-of-Way
    - Right-of-Way acquisition
    - Right-of-Way clearing requirements
    - Right-of-Way width
- Permitting Concerns
    - Traffic control requirements
    - FAA Requirements
- Environmental Concerns
    - Environmental Study Requirements
    - Wetland Requirements/Mitigation
    - Threatened and Endangered Species Mitigation
    - Cultural/Historical Resource Requirements

Transmission Substation Projects

- Preliminary one-line diagram
- All major equipment, including rehab of existing equipment to meet the SPP project scope, i.e. Transformers, Breakers, Control panels, Switches, CTs, PTs, CCVTs
- BIL ratings
- Contamination requirements
- Mobile substation requirements

- Required substation property/fence expansions (indicating anticipated arrangement of proposed facilities and any resulting expansion needed)
- Control enclosure expansions (indicating anticipated panel layout and any resulting expansion needed)
- Fiber optic requirements
- Remote end requirements
- Metering requirements
- Reactive Compensation requirements
- Wetland/T&E/Community Approval/Unusual site prep requirements.
- SCADA requirements

SPP Regional Trustee Update

June 2011
NERC Planning Committee

July 25, 2011

Noman Williams
nlwilliams@sunflower.net
785.623.3332

SPP Southwest Power Pool

PC Elections

Elections of Chair and Vice Chair

Election of Chair – Jeff Mitchell

Election of Vice Chair – Ben Crisp

PC Strategic Plan and PC Charter changes

- PC approved their Strategic Plan and modifications made to the Charter to align with the Strategic Plan
- Strategic Plan and Charter will be taken to the BOT for approval in August

SPP 3

Eastern Interconnection Wide Area SynchroPhasor Angles Baselining Study

- The primary goal of this project was to:
  - Investigate phasor angle differences between site pairs
  - Characterize typical patterns and identify atypical events
  - Recommend upper and lower limits for "normal" operation
- Understanding these issues will likely result in:
  - Increased understanding of the significance of Phasor Angle Differences as a metric of grid stress & health
    - Increased grid reliability
- Conclusions and Next Steps
  - This research appears to result in an analytical tool that may help understand how to use the Phase Angle pair differences to monitor the grid.
  - Investigate Methods of determining Bus Angle Pairs to Monitor

SPP 4

Improved Processes and Procedures for Interconnection-wide Modeling

- It is important to have good quality steady-state and dynamic bulk power system models available for industry action
- Development of power flow and dynamic models will be through coordinated regional efforts
- Reviewed several different options for this effort and the following option was chosen:
  - *Leverage existing structures: Assign NERC staff to lead ERO-RAPA oversight of model development activities in each interconnection. Support enhancements and improvements*.
- Have a meeting on June 29th with EPRI to leverage the information and involvement of the folks that actually build the models.
- Concerns that this could potentially impact other groups and the work that they do – intent is to support their efforts and improve the overall accuracy of the models and help the modeling effort.
- Concern that there is an overall lack of expertise within the companies to do modeling, maybe work on providing education and sharing of best practices between the regions.

ERCOT February 2, 2011 Grid Emergency Events

ERCOT provided a very good overview analysis of this event.

- An interesting observation: they used load shedding as a way to control/limit frequency decay.
- Exploring the interdependence of electric service for gas supply but have not yet identified any specific issues

- Next Steps and findings:
  - continue to review the actions leading up to this event and the handling of event itself.
  - is providing information to assist in the investigations currently underway.
  - will be an active participant in the discussion related to the adequate weatherization of generation units.
  - will work with transmission providers to study the potential use of advanced meters in selective load reduction.
- is reviewing all communications policies related to grid emergencies
  - has already implemented changes that will provide automated notice to the State Operations Center (SOC) and the PUC.
  - will implement a "phone bank" that will temporarily increase staff during emergency situations to respond to incoming calls.

PC - Subgroups Update

Reliability Assessment Subcommittee (RAS)

- Publish one annual report on ERO historic reliability performance:
- The Annual State of Reliability Report will:
  - Communicate the effectiveness of reliability improvement programs
  - Provide an integrated view of risk
  - Critical Infrastructure Protection / Standards Development / Compliance
  - Event Analysis
  - Report bulk power system and equipment performance
  - Integrated view using GADS, TADS, DADS, & Event data
  - Plan to transition From "*2011 Reliability Performance Analysis Report*" to "*State of Reliability Report 2012*"
- Reliability Assessments
  - Validate assessment with Regional Entities for accuracy and completeness
  - PC will reviewed and provide recommendations by July 30, 2011 on the Risk Factors to be used in the Reliability Assessments
  - Reviewed the schedule for seasonal/post seasonal assessments
  - Post season – looking at lessons learned

SPP 7

PC - Subgroups Update

BES Definition and Exemption Process - Issues and Questions

- Should facilities and equipment located on the distribution system be considered part of the BES based on their BES reliability function; e.g., demand response controls; UFLS; UVLS; etc.
- Transition plan for newly identified facilities and elements; need for "grandfathering"?
- Can responsibility for BES facilities of small entities be assigned to other entities; can JRO and CFR procedures provide for this?

Events Analysis Working Group (EAWG):

- Field test is in second phase
- Phase 2 document is on NERC website
- 3 month field test started May 2nd
- 3rd version by Oct 1, 2011, plan to include CPS in phase 3
- 51 events – 6 published
- 321 issues recorded and tracked, 128 of those qualified as cat 1-4 , no 5 , 1 cat4 , 5 cat 3, 40 cat 2 , 80 cat 1 and 93 cat 0.

SPP 8

PC - Subgroups Update

ALR Issues and Questions

- Should ALR address resilience to and recovery from physical and/or cyber attacks?
- Should cost/benefit be factored into ALR? How and by whom should decisions be made?
- Is impact of all load loss equal; e.g., load shed in response to EEA-3 vs. system disturbances?
- How should "cascading" be defined?
- Do we have adequate metrics for current attributes of ALR?

ALR Recommendations

- How should cost/benefit be factored into ALR? How and by whom should decisions be made?
  - Recommendation: *Assess the reliability benefits of ALR criteria and explicitly calculate the cost-effectiveness of requirements within a reliability standard to meet the reliability objectives*
- Is the impact of all load loss equal?
  - Recommendation: *Revise ALR defining criteria to address loss of supply, transmission and controlled/uncontrolled load loss as a function of operational planning and operator preparations, as well as the resulting normal and abnormal operating states.*
- How should "cascading" be defined?
  - Recommendation: *No change*

SPP 9

PC - Subgroups Update

Spare Equipment Database Task Force (SED):

- Participation:
  - Voluntary by ALL NERC registered TOs and GOs
- Content:
  - Long-lead time (6 months-plus) transformers including:
    - transmission: low side rating of 100kV or higher & max nameplate rating of 100 MVA or higher (all 3 phases)
    - GSU: high side voltage of 100KV or higher and max nameplate rating of 75 MVA or higher (all 3 phases)
- Operations:
  - 24x7 online program operated by NERC vendor; start 2012
  - Confidentiality:
    - Secure database with mandatory SED confidentiality agreement
      - Submitting Whitepaper for approval at the Sept. 13-14 PC meeting.
      - Developing by Sept. 30th a functional specification for use in selecting an SED vendor.
      - Initiating a one-year trial program amongst SED participants in 2012.

SPP 10

PC - Subgroups Update

Potential Bulk System Reliability Impacts of Distributed Resources Report Development:

- Scope and Objectives:
- Assess potential adverse bulk system reliability impacts of high levels of DR
  - include all distributed resources, whether variable or not
  - distributed generation, including PV and DR
- Conclusions/Recommendations:
  - Evaluate whether distributed resource owners/operators should have to register as part of NERC Functional Model
  - At high penetrations, DR can adversely impact bulk system reliability if not properly planned and operated
  - Potential adverse impacts can be mitigated:
    - Visibility and controllability of DR from bulk system needed
    - New standards to ensure compatible interconnection of DR
    - Compatibility with existing standards such as IEEE 1547
- No specific recommendations for standards or NERC Registry Criteria changes are made

SPP 11

PC - Subgroups Update

Transmission Availability Data Systems Working Group (TADSWG)

- Approve TADSWG to work on a draft request for comments (under Rules of Procedure 1600
  - Consistent with the updated EIA-411
  - This will capture an additional 127 TO's who do not currently report (196 existing TO)
  - This will increase the AC circuits by 2.5 times will increase by ~17,400 elements (current 6,694)
- Current TADS Format:
  - Utilize existing webTADS data structure for data collection
  - Advantages: Builds on existing webTADS platform and summary reporting including…
    - Providing data for ALR6-11 to ALR6-16 metrics
    - Automated consistent error checking
    - Supporting Event analysis for common & dependant mode Events
    - Supporting analysis of near simultaneous outages
    - Cross-references to EOP Disturbance Reports, PRC mis-operations reports, GADS events & DADS events
- Schedule: TADSWG to prepare draft Data Request for PC approval by May 2012 for implementation by January 1, 2014.

SPP 12

PC - Subgroups Update

System Protection and Control Subcommittee (SPCS)

- Approved – posting of SPCS guideline: "Transmission System Phase Backup Protection"
  - *Conclusions:*
    - Events have shown that backup protection can play a significant role in preventing or mitigating the effects of Protection System or equipment failures
    - The design of the power system and local protection design practices dictate whether local or remote backup protection can be securely and dependably applied to meet NERC standards for power system and Protection System performance
    - Careful examination of the overall interaction of Protection Systems may provide insight as to where additional local or remote backup can be applied to help mitigate the spread of an outage.
- *Recommendation from guideline*
  - The SPCS recommends that back up Protection Systems be applied to large autotransformers to reduce the likelihood of damage due to prolonged through fault currents caused by the failure of local or remote Protection Systems to clear the fault
    - Large autotransformers are major capital investments and play a large role in the reliability and flexibility of the Bulk Electric System
    - Lead times for obtaining replacements are typically a minimum of six to twelve months; therefore, failures of these transformers can result in prolonged reduction in Bulk Electric System reliability and flexibility

SPP 13

PC - Subgroups Update

Transmission Issues Subcommittee (TIS)

- TIS recommendation of the frequency response criteria
- Believe that for the eastern IC the loss of 10,000 MW would trigger UFLS. However no single event would rise to this level:
  - The largest category C event is Eastern IC at 3420 MW
  - The Largest Total Plant with Common Voltage Switchyard Eastern IC at 4779 MW
  - Largest Resource Event in Last 10 Years Eastern IC at 4500MW
- Std Committee is looking at a probabilistic approach to the standard.
- Eastern interconnection is currently running at 2,200 MW – freq response calculated using historical method.
- Approved frequency response obligation as recommended

SPP 14

Planning Committee Update

Questions