Southwest Power Pool

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

October 23rd, 2014

Westin DFW – Irving, TX

• SUMMARY OF ACTIONS TAKEN •

1. ESWG members approved the September 18th and October 3rd minutes, as amended.
2. ESWG members requested RARTF support of allowing additional time in the RCAR II schedule for member review of modeling data and metrics analysis.
3. ESWG members approved the 2014 Probabilistic Assessment report as amended.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

October 23rd, 2014

Westin DFW – Irving, TX

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains, LLC) called the meeting of the Economic Studies Working Group (ESWG) to order at 9:32 AM, welcomed those in attendance, and asked for introductions. (Attachment 1 – October 23rd, 2014 Attendance List)

There were 15 in-person participants and 42 web conference participants representing 12 of 13 ESWG members.

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains, LLC) asked for any proxy statements. No proxies were identified.

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains, LLC) presented the agenda for review and asked for any additions or corrections. Alan Myers asked for an item after item #10 to provide an update to the group on MOPC and SPC activities. (Attachment 2 – October 23rd, 2014 Agenda)

> **Kip Fox (AEP Transource) made a motion to adopt the agenda as amended. Kurt Stradley (LES) seconded. The motion was approved unanimously.**

Agenda Item 2 – Review of Past Action Items

Kelsey Allen (SPP Staff) reviewed the list of action items with the group. (Attachment 3 – Action Items)

Agenda Item 3 – Consent Agenda

The Consent Agenda included the following item:

> Approval of Meetings Minutes – September 18th, 2014 (Attachment 4 – ESWG 9.18.14 Minutes)
> Approval of Meetings Minutes – October 3rd, 2014 (Attachment 5 – ESWG 10.3.14 Minutes)

An addition to the proxy statements was included in the September 18th minutes.

> **The consent agenda was approved unanimously as amended.**

Agenda Item 4 – 2015 ITP10 Schedule

Juliano Freitas (SPP Staff) gave an update on the status of the 2015 ITP10. Staff has been working through comments and making adjustments to the final portfolios based on member feedback through the sub regional conference calls and RMS requests. Staff will be seeking approval that development of the final portfolio is complete from the ESWG and TWG on October 29th. Once the portfolios are complete Staff will begin project staging analysis and final assessments. (Attachment 6 - 2015 ITP10 Schedule)

Agenda Item 5 – RCAR II Schedule

Juliano Freitas (SPP Staff) gave an update on the status of the RCAR II. Staff is currently working on economic model development and constraint assessments. Power flow model development is complete and Staff is seeking approval of the models from the TWG. Phase 1 of the RCAR II is scheduled for a January 2015 completion, with phase 2, which will include the 2015 ITP10 approved projects, is scheduled for April 2015 completion. 40-year benefit calculations will be extrapolated from the delta between 2019 and 2024 data points. Staff proposed a one week member review period for the economic model and constraints. The members expressed strong concern that this was not enough time to properly review the data, also noting that it is important for the group to be able to weigh in on Brattle's calculation of the metrics once complete. Bary Warren (Empire) expressed the importance of the RCAR II process and offered the consideration of a July 2015 completion. (Attachment 7 – RCAR II Schedule)

Kip Fox (AEP Transource) made a motion to request additional time in the RCAR II schedule for member review of modeling data and analysis, and solicit support from the RARTF to allow the request. Pat McCool (KCPL) seconded. The motion was approved unanimously.

ACTION ITEM: SPP Staff will prepare a graphical representation of the APC extrapolation that will be utilized for 40-year analysis in the RCAR II.

ACTION ITEM: SPP Staff will communicate the ESWG request for additional time in the RCAR II schedule internally with Staff involved in the RARTF.

Agenda Item 6 – 2015 ITP10 Final Portfolios

Kelsey Allen (SPP Staff) gave an update on the status of ITP10 portfolios development. Staff did not present on the portfolios today but plan to seek approval next week on the 29th. Discussion continued on project and analysis specifics of the current chosen portfolios, including the level of benefits and impacts considered during Staff analysis, request for modeling data used during analysis, request for more detail on the reasoning for project adjustments, request for project cost details, and request for a more comprehensive list of needs mitigated by the final portfolios. The group requested more detail to confirm Staff analysis and make a no regrets decision when asked to approve the completion of the project selection process.

ACTION ITEM: SPP Staff will investigate posting modeling data for final portfolios prior to approval.

ACTION ITEM: SPP Staff will include more detail about the reasoning for project selection changes.

ACTION ITEM: SPP Staff will provide a list of economic constraints addressed by both reliability and economic projects.

Agenda Item 7 – 2015 ESWG Meeting Schedule

Kelsey Allen (SPP Staff) proposed dates and locations for the upcoming 2015 ESWG face to face meetings. Staff solicited feedback in order to make any necessary adjustments and look for approval at the November. The members urged staff to review the study schedules for next year and investigate the need for any 2-day meetings. (Attachment 8 – 2015 ESWG Meeting Schedule)

ACTION ITEM: SPP Staff will review the 2015 study schedule and investigate the need for 2-day ESWG meetings.

Agenda Item 8 – 2015 ITP10 Report

Amber Greb (SPP Staff) reviewed the process of report development, current progress of the 2015 ITP10 report, and schedule expectations moving forward. Part 2 of the report is currently out for review, with part 3 scheduled to be posted on December 11th. In order to meet the final report deadline of January 2nd, review periods will be short; Staff is requesting feedback on Part 2 on November 6th. Members expressed concern with the short time frames but understand the tight schedule. Amber then touched on key points of the report and asked for member feedback. The members requested more detail related to phase 2 of the economic project selection process, detail about policy needs and projects and how each company met its policy requirements, and capacity factor detail for renewables. (Attachment 9 – 2015 ITP10 Report) (Attachment 10 - Draft 2015 ITP10 Report Part 2)

Discussion shifted to accuracy of analysis and software improvements that could be made to address certain concerns. The members requested that someone from Ventyx

Agenda Item 9 – Probabilistic Assessment Report

Seth Mayfield (SPP Staff) updated the group on the status and next steps for the Probabilistic Assessment. He detailed a minor change in the current report and requested approval from the group.

(Attachment 11 – Probabilistic Assessment Final Report) (Attachment 12 – SPP 2014 Probabilistic Assessment Final Report) (Attachment 13 – 2014ProbA_SPP1)

Kip Fox (AEP, Transource) made a motion to approve the report as submitted and amended by SPP Staff. Leon Howell (OGE) seconded. The motion was approved unanimously.

Agenda Item 10 – ITP Load and Generation Review

Kelsey Allen (SPP Staff) presented a proposal to the group to improve the ITP load and generation review process in order to gain accuracy and consistency in models used by SPP and the membership. It involves creating a subset of the economic model data that will be reviewed by the MDWG as a part of their annual model development process. The idea is to gain consistency between MDWG and ITP load and generation data as well as more accuracy in the PROMOD data. (Attachment 14 – ITP Load and Generation Review)

Agenda Item 11 – MOPC/SPC Update

Alan Myers (SPP Staff) updated the group on discussion and actions taken at the October MOPC and Strategic Planning Committee (SPC) meetings. In July, the BOD directed Staff to seek a waiver to forgo the ITP20 in the next ITP cycle due to integration of the Integrated System and uncertainties surrounding the Clean Power Plan (CPP) in EPA section 111D. The SPC approved a motion to delay the start of the next ITP10 study by 6 months, to begin in July 2015. The ESWG recommended using the extra 6 months to look at a broader range of futures, lengthening the ITP10 to a 24 month study with futures development starting in January 2015 and study work to begin in July. The MOPC approved the ESWG recommendation and gave the flexibility to shift the start of the study work consistent with the EPA release of the CPP ruling. Paul Dietz (Westar) stressed that the stakeholders consider the strategic implications of the decisions we make related to waiving the ITP20, impacts in the DPP process, and overall concerns with the quality of work product.

Agenda Item 12 – 2017 ITP10 Scope and Futures

Amber Greb (SPP Staff) opened the floor for discussion of Futures development for the 2017 ITP10. The group brainstormed on a multitude of options for Futures and inputs that may be considered. A few general comments and process ideas were touched on throughout the discussion:

- Test sensitivities to determine trigger points during futures and resource plan development to better define inputs.
- Quantify the weaknesses of the transmission system and determine the impact of the different Futures.
- Look at a wide range of Futures and develop a transmission plan that addresses issues across all of them, not necessarily focusing on the BAU.
- Keep Futures on the table as long as possible during development.

The discussion led to a number of Futures ideas that will be discussed more at the November meeting:

- Solving 111D
  - Locally
  - Regionally
  - With Renewable Energy Credits
- Green future
  - 10% load reduction due to distributive generation
  - 111D passed at 100%
  - RPS
- Hyper-Physical Security
- Environmental regulations due to climate change are reversed
- Extensive West Connectivity
- Severe Weather: Long-Term Drought
- Severe Weather: Winter impacts
- Substantial Solar Development
- Competitive Wind

- High-Supply NG Due to Fracking
- Low-Supply NG Due to Fracking Regulation
- ERCOT joins the Eastern Interconnect
- Technology Advancement
- Significant Deregulation (Retail Level)
- High Growth
- Low Generation
- Financial Expansion cap
- Economic Collapse
- Significant Cost of Capital increase

(Attachment 15 - 2017 ITP10 Scope and Futures) (Attachment 16 - ITP Futures (SPP Scenario Development - Brattle))

ACTION ITEM: SPP Staff will summarize and organize the Futures brainstorm for discussion at the next ESWG meeting.

Agenda Item 13 – SPP.org

This item was stricken from the agenda and will be covered at a later date.

Closing Items

Chair Alan Myers (ITC Great Plains, LLC) requested other items meriting discussion.

The meeting was adjourned at 2:45 PM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Name	Company	Attendance
Al Tamimi	Sunflower	Webex
Alan Myers	ITC	In-Person
Amanda Weaver	GSEC	Webex
Amber Greb	SPP	In-Person
Antoine Lucas	SPP	Webex
Bary Warren	Empire District	In-Person
Bennie Weeks	Xcel/SPS	In-Person
Bill Leung (NPRB)	NPRB	Webex
Bruce Walkup (AECC)	AECC	Webex
Chris Jamieson - SPP	SPP	Webex
David Spargo	OPPD	Webex
Don Le	NextEra Energy Transmission	In-Person
ed pfeiffer (quanta)	Quanta	Webex
Erik Winsand (ATC)	ATC	Webex
Gayle Freier (SPP)	SPP	Webex
Gimod Olapurayil (ITC)	ITC	Webex
Heather Starnes (MJMEUC/CU)	MJMEUC/CU	Webex
Jason Schmidt	Xcel	In-Person
Jason Shook (GDS/ETEC)	ETEC	Webex
Jeremy Harris	Westar	Webex
Jeremy Severson	BEPC	Webex
Jerry Bradshaw (SPRM)	SPRM	Webex
Joe Fultz	GRDA	Webex
John Boshears (SPRM)	SPRM	Webex
John Mills	SPP	Webex
Jordan Schmick	Xcel Energy/SPS	In-Person
Josh Verzal	OPPD	Webex
Josh York	LS Power	Webex
Juliano Freitas	SPP	In-Person
Kelsey Allen	SPP	In-Person
Kevin Foflygen	CUS	Webex
Kip Fox	AEP, Transource	In-Person
Kirk Hall	SPP	Webex
Kurt Stradley (LES)	LES	Webex
Leon Howell	OGE	In-Person
Meena Thomas	PUCT	Webex
Michael Quinn	Oncor Electric Delivery	In-Person
Michael Watt (OMPA)	OMPA	Webex
Michael Wegner	ITC	In-Person
Mike Knapp (OCC)	OCC	Webex
Nicole King	OCC	Webex
Pat Hayes (Ameren)	Ameren	Webex
Paul Dietz	Westar	Webex
Randy Collier (CUS)	CUS	Webex
Robert Safuto (Customized Energy Solutions)	Customized Energy Solutions	Webex
Rosemary Mittal	SPP	Webex

Sandeep Baidwan	LS Power	Webex
Seth Mayfield	SPP	Webex
Steve Gaw	Wind Coalition	Webex
Ted Bell, SPP	SPP	Webex
Terri Gallup (AEP)	AEP	Webex
Tim Owens (NPPD)	NPPD	Webex
Tim Soles	Occidental	In-Person
Todd Tadych (DATC)	ATC	Webex
Tom DeBaun (KCC)	KCC	Webex
Trent Carlson		Webex
Wayman Smith	AEP	In-Person
Zac Hager	OGE	In-Person

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

October 23rd, 2014

Westin DFW, Irving, TX

• A G E N D A •

8:30 am – 2:30 pm

1. Administrative items
   a. Call to Order, Introductions........Alan Myers (5 minutes)
   b. Receipt of Proxies........Kelsey Allen (1 minute)
   c. Review of Agenda........Alan Myers (1 minute)
2. Review of Past Action Items........Kelsey Allen (5 minutes)
3. Consent Agenda (Approval Item)[1]........Alan Myers (5 minutes)
   a. Approval of Meetings Minutes – September 18th, 2014
   b. Approval of Meetings Minutes – October 3rd, 2014
4. 2015 ITP10 Schedule........Juliano Freitas (5 minutes)
5. RCAR II Schedule........Juliano Freitas (5 minutes)
6. 2015 ITP10 Final Portfolios........SPP Staff (30 minutes)
7. 2015 ESWG Meeting Schedule........Kelsey Allen (45 minutes)
8. 2015 ITP10 Report........Amber Greb (90 minutes)
9. Probabilistic Assessment Report (Approval Item)........Seth Mayfield (30 minutes)
10. ITP Load and Generation Review........Kelsey Allen (15 minutes)
11. MOPC/SPC Update........Alan Myers
12. 2017 ITP10 Scope and Futures........SPP Staff (60 minutes)
13. ~~SPP.org........Pete Hoelscher (30 minutes)~~
14. Closing Items........All

[1] Background materials included

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

October 23rd, 2014

ID	Action Item	Date Originated	Status	Comments
057	SPP staff will write a straw-man procedure or portion of the ITP manual that deals with conventional and wind generation planning and siting within the ITP process. The process should be in place by the Spring of 2015.	August 23, 2012	In Progress Staff	Staff will provide a draft report in November 2014.
076	ESWG will analyze the aggregate studies impact on the 2015 ITP10 study for transmission service request.	May 16, 2013	In Progress ESWG Members	Item on hold, wait for Aggregate Studies new results
087	ESWG members and SPP Staff will compare the generation resources in the different models used in the SPP studies processes.	August 13, 2013	In Progress	Staff presented process improvement recommendation to address generation differences between PROMOD and models used in other SPP studies.
127	SPP Staff will develop a process to address interaction between SPP departments (Generation Interconnection, Aggregate Studies, Economic Planning, Steady State and Modeling) to detect basic errors in our models.	August 7, 2014	In Progress	
128	SPP Staff will explain to ESWG Members the process to submit data to model on demand.	August 7, 2014	In Progress	
130	SPP Staff will provide details to the members in how the SPC, TWG and ESWG will coordinate efforts to decide about the Future's assumptions.	August 7, 2014	In Progress	
134	SPP Staff will communicate the ESWG request for additional time in the RCAR II schedule internally with Staff involved in the RARTF.	October 3, 2014	In Progress	

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

September 18th, 2014

AEP Offices – Dallas, TX

• SUMMARY OF ACTIONS TAKEN •

1. ESWG members approved the August 7th minutes.
2. SPP Staff will send an email to ESWG members to see if October 2nd or 3rd would be preferred for a meeting to talk about the portfolios that will be posted October 1st.
3. SPP Staff will provide the draft Probabilistic Assessment to ESWG for review when it is sent to NERC.
4. ESWG accepted Staff's cosmetic changes to the finalized 2011 ITP Manual, to be used as the starting point for the 2014 ITP Manual by email vote on October 9th.

Southwest Power Pool

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

September 18th, 2014

AEP Offices – Dallas, TX

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains, LLC) called the meeting of the Economic Studies Working Group (ESWG) to order at 9:32 AM, welcomed those in attendance, and asked for introductions. (Attachment 1 – Attendance List)

There were 15 in-person participants and 50 web conference participants representing 9 of 13 ESWG members.

Agenda Item 1b – Receipt of Proxies

Juliano Freitas (SPP Staff) asked for any proxy statements. Two proxies were identified; Kip Fox (AEP-Transource) named Wayman Smith (AEP-Transource) as his proxy. Kurt Stradley (LES) named Tim Owens (NPPD) as his proxy. (Attachment 2 – Proxies)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains, LLC) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – Agenda)

Tim Owens (NPPD) made a motion to adopt the agenda. Wayman Smith (AEP Transource) seconded. The motion was approved unanimously.

Agenda Item 2 – Review of Past Action Items

Juliano Freitas (SPP Staff) reviewed the list of action items with the group. No additional action items were added. (Attachment 4 – Past Action Items)

Agenda Item 3 – Consent Agenda

The Consent Agenda included the following item:

> Approval of Meetings Minutes – August 7th, 2014 (Attachment 5 – ESWG 8 7 14 Minutes & Attachments)

ESWG Members approved the consent agenda unanimously.

Agenda Item 4 – 2015 ITP10 Schedule

Juliano Freitas (SPP Staff) gave an update on the 2015 ITP10 Schedule. SPP Staff plans to post all projects received and tested on October 1st. At the October 8th Summit, Staff intends to talk about groupings and the final portfolio. Staff will be seeking approval for the final portfolio from the ESWG and TWG toward the end of October. Members showed concern with the current schedule and the lack of time to provide feedback with approval at the end of October. (Attachment 6 - 2015 ITP10 Schedule)

ACTION ITEM: SPP Staff will send an email to ESWG members to see if October 2nd or 3rd would be preferred for a meeting to talk about the portfolios that will be posted October 1st.

Agenda Item 5 – RCAR II Schedule

Juliano Freitas (SPP Staff) updated the group on the status of the RCAR II Schedule. On August 21st, the ESWG had an email vote on the 2034 Resource Plan. The plan was approved with a 9-0-0 vote. The constraint assessment is set to start next week. Staff also put together an external resource plan for the 20-year model utilizing the same methodology as in the 2015 ITP10 (Attachment 7 – RCAR II Schedule)

Agenda Item 6 – Probabilistic Assessment

Seth Mayfield (SPP Staff) gave an update on the Probabilistic Assessment. Topics included LOLE study characteristics and data inputs, thermal and wind generation, flowgate and contingency modeling, and transaction modeling. Next steps are to take a draft to NERC and also have a peer review. (Attachment 8 - Probabilistic Assessment Overview)

ACTION ITEM: SPP Staff will provide the draft Probabilistic Assessment to ESWG for review when it is sent to NERC.

Agenda Item 7 – BPR-054 Update

Brett Hooton (SPP Staff) gave the ESWG an update on Business Practice 054. This business practice is "to describe the process and timeline for the creation and publication of a Request for Proposal ("RFP") for a Competitive Upgrade as outlined in Attachment Y, Section III of the SPP Tariff." This will be taken to the MOPC for approval at the October 2014 meeting. (Attachment 9 - BPR054_Request for Proposal_Draft 073114 bb BPWG 8-7 PCWG 8-12-2014Staff 8-29-14 BPWG 9-4-2014 clean)

Agenda Item 8 – Seams Policy Paper

Brett Hooton (SPP Staff) gave an update on the Seams Project Task Force activities involving finalization of a policy white paper which outlines seams projects criteria for study and approval. (Attachment 10 - Seams Projects TF Update 9.11.14) (Attachment 11 - Draft Seams Policy Paper 090914 Approved by SSC)

Agenda Item 9 – SPP-MISO Study Update

Brett Hooton (SPP Staff) gave an update on the SPP-MISO Coordinated System Plan (CSP) study. Model development is currently under way and issues will be reviewed at the October IPSAC meeting with solution development to follow. Brett also gave a short update on the SPP-AECI joint study which is currently in the solution development phase. (Attachment 12 - SPP-MISO Study Update)

Agenda Item 10 – EPA Clean Power Plan

Jay Caspary (SPP Staff) presented on the EPA Clean Power Plan and the impacts it has on the SPP region. Jay presented the results from the reliability analysis, SPP Staff applied the retirements suggested by EPA, the retired units were replaced by CC and CT using the 2015 ITP10 siting plan. The main issue is the lack of reactive power caused by base load units being retired; the study also has the additional findings:

- Before considering the impacts of contingencies, preliminary results indicate increased thermal overloads and low voltages due to EPA's assumed retirements. More concerning were several summer peak cases which would not solve under N-1.
- Updated scenarios for summer peak conditions with significant gas-fired generation expansion and increased wind developments based on optimal ITP resource plans. Reliability issues were not mitigated, but actually increased, despite optimal generation expansion.
- Additional sensitivities in process now to evaluate impacts of delays in installing replacement capacity, as well as lower loads as a result of more energy efficiency initiatives. Share results at upcoming 9/19 SPC meeting.

The data summarized in the presentation was gathered from reports developed and published by the EPA. (Attachment 13 - SPP CPP Impacts)

Agenda Item 11 – ITPNT Update

Kirk Hall (SPP Staff) presented on a proposal to change the ITPNT cycle. Staff proposal is to start the next ITPNT on May 1, 2015. This will better align the near-term assessment with the model build process and allow a full 12 months for performing analysis. Also, shifting the starting date will more effectively space the DPP windows for the ITP20, ITP10 and ITPNT. (Attachment 14 - ITPNT Cycle Change Proposal_R1)

Agenda Item 12 – 2016 ITP10 Scope and Futures

Juliano Freitas (SPP Staff) presented the general requirements, data needs and ESWG responsibilities for the 2016 ITP10. Juliano also covered the Staff capabilities and estimated man hours to complete different numbers of Futures for the study. Most of the discussion centered on the study timeframe and futures development process. The ESWG prefers to begin the next ITP10 cycle in January 2015 and start discussion about the assumptions and number of Futures, this discussion will involve the TWG and SPC, the proposed Futures will be narrowed down with MOPC feedback for the final set of Futures to be presented to the MOPC in April 2015. The first six months in 2015 will be utilized to develop the 2016 ITP10 scope, model development and analysis will performed in the next eighteen months starting in July 2016, the total time for study completion is twenty four months.(Attachment 15 - 2016 ITP10 Scope and Futures) (Attachment 16 - 2015 ITP10 Futures) (Attachment 17 - 2016 ITP10 Scope Summary)

Agenda Item 13 – ITP Manual

Paul Dietz (Westar) gave an update on the progress of the ITP Manual Task Force. They are currently reviewing the Staff edits made since the manual was last approved in 2011. The TF would like ESWG approval of Staff edits prior to updating the manual to 2014 standards. Review of these edits will be complete by October 2nd. Paul also presented the draft outline for the final manual. (Attachment 18 - ITP Manual DRAFT Outline Accepted Redline Version 8-28-2014) (Attachment 19 ITP_Manual Task Force edits – clean) (Attachment 20 - ITP_Manual Task Force edits – redlined)

Following the manual review, on October 7th SPP Staff recommended that the ESWG accept Staff's cosmetic changes to the finalized 2011 ITP Manual, to be used as the starting point for the 2014 ITP Manual.

Paul Dietz (Westar) made a motion to accept Staff's cosmetic changes to the finalized 2011 ITP Manual, to be used as the starting point for the 2014 ITP Manual. Kip Fox (AEP Transource) seconded. The motion was approved unanimously.

Closing Items

Chair Alan Myers (ITC Great Plains, LLC) requested other items meriting discussion.

The meeting was adjourned at 2:08 PM.

Respectfully Submitted,

Kelsey Allen

ESWG Secretary

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

October 3rd, 2014

Conference Call

• SUMMARY OF ACTIONS TAKEN •

1. SPP Staff will send an email to working groups explaining how SPP wants to receive member questions on projects.
2. SPP Staff will check with the legal department to see if they can post staff solutions. Staff will also check to see if we can post which need(s) each project addresses.
3. SPP Staff will provide a list, in the ITP10 report, of any individual Wind Farm that was significantly curtailed during the Policy Assessment.
4. SPP Staff to look into adding columns to the project list to show if a project is based on reliability or economics, and also to list the states where the project is located.

Southwest Power Pool

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ECONOMIC STUDIES WORKING GROUP

October 3rd, 2014

Conference Call

• MINUTES •

Agenda Item 1 – Administrative Items

Juliano Freitas (SPP Staff) informed the group that the October 23rd ESWG meeting will begin at 8:30. The ITP Manual Task Force will have a short meeting after the ESWG on October 23rd.

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains, LLC) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:35 AM, welcomed those in attendance, and asked for introductions. (Attachment 1 – Attendance List)

There were 1 phone participants and 59 web conference participants representing 12 of 13 ESWG members.

Agenda Item 1b – Receipt of Proxies

Juliano Freitas (SPP Staff) asked for any proxy statements. No proxies were identified.

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains, LLC) presented the agenda for review and asked for any additions or corrections. (Attachment 2 – Agenda)

The motion was approved unanimously.

Agenda Item 2 – Discuss Summit Posting Materials (ITP10)

Juliano Freitas (SPP Staff) gave an update on the 2015 ITP10. The presentation was to present the methodology applied by SPP Staff to develop the final groupings per Future as well the proposed Consolidated Portfolio. During the presentation Juliano discussed the methodology utilized to select reliability and economic projects; during the current study SPP Staff did not identify policy needs. The project selection was based on a methodology approved the ESWG in May 2014 consisting in three phases, Juliano provided details about each phase. In the second part of the presentation Juliano discussed the preliminary grouping statistics, preliminary portfolio overviews (including maps), and a draft Consolidated Portfolio. The preliminary statistics included the total mileage, total cost and B/C ratio for economic projects. Individual projects will be addressed during the Sub-Regional calls to be scheduled after the Engineering Planning Summit at October 8th. The last part of the presentation showed a list of Seams projects, one project was included in the Final Portfolio and the four remaining ones are under further evaluation depending on the cost ratio associated with SPP-AECI negotiations. SPP Staff will ask for ESWG and TWG approvals regarding the consolidated portfolio by the end of October in order to keep the current schedule and finish the final report before the MOPC in January. (Attachment 3 – 2015 ITP10 Overview)

ACTION ITEM: SPP Staff will check with the legal department to see if they can post staff solutions. Staff will also check to see if we can post which need(s) each project addresses.

ACTION ITEM: SPP Staff to look into adding columns to the project list to show if a project is based on reliability or economics, and also to list the states where the project is located.

Closing Items

Chair Alan Myers (ITC Great Plains, LLC) requested if any other items merited discussion.

The meeting was adjourned at 10:26 AM.

Respectfully Submitted,

Kelsey Allen

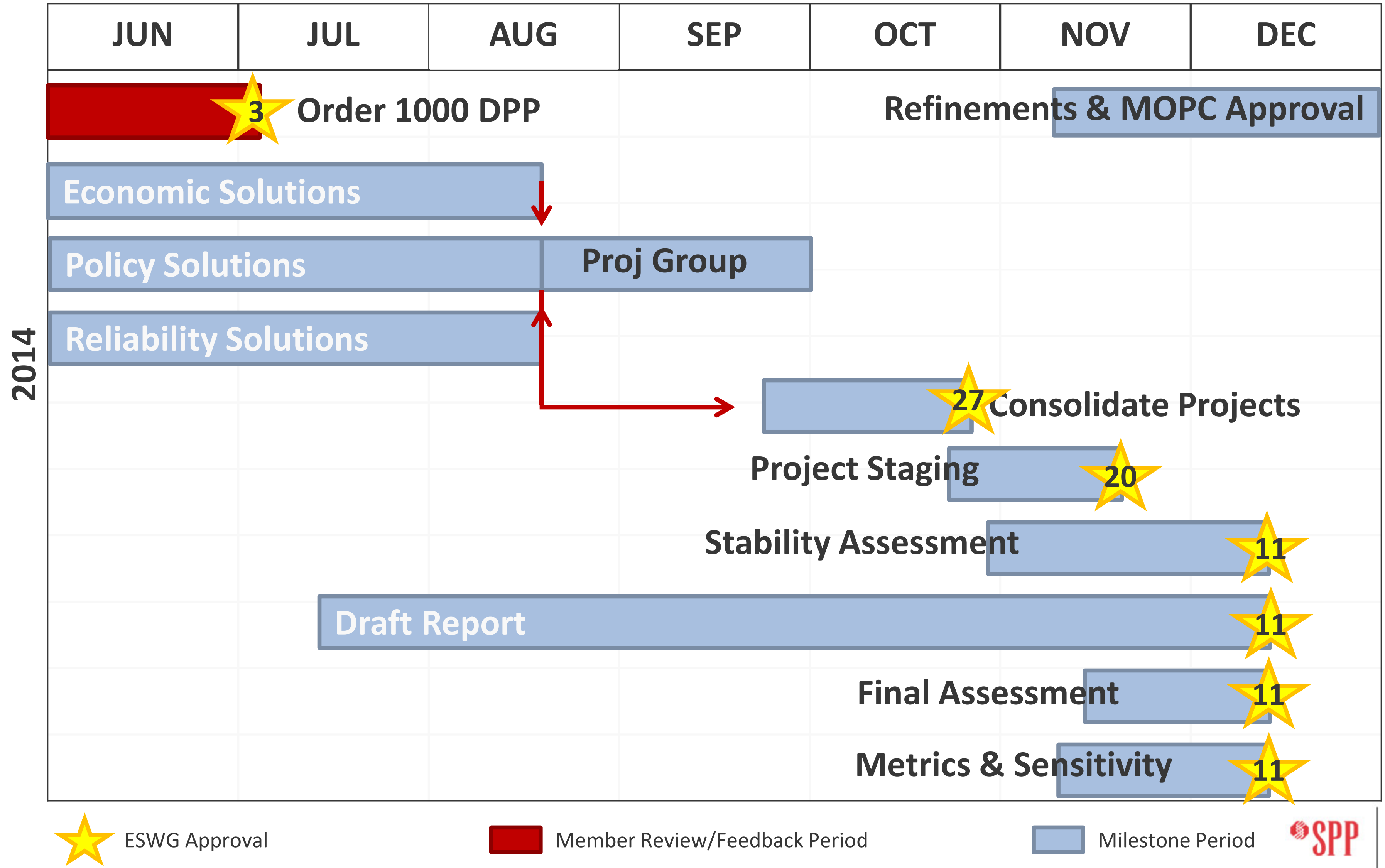
ESWG Secretary

2015 ITP10 Schedule

October 23th, 2014

Southwest Power Pool

ITP10 Milestone Schedule (Jun-Dec 2014)



ITP10 Milestone Schedule - Summary

Task Name	Start	Finish	Member Feedback	ESWG Approval
Scoping	April	October	17 weeks	10/2
Policy Survey	May	August	9 weeks	12/04
Load and Generation Review	May	September	10 weeks	9/5
Resource Plan	August	October	3 weeks	12/04
Siting Plan	September	October	2 weeks	12/04
Economic Model development	June	February	7 weeks	Feb 21/2014
Benchmarking	November	January ’14	1 week	Feb 13/2014
Constraint assessment - TWG Approval	November	March ’14	1 week	
DC to AC Conversion of Peak Hours	January	March	2 weeks	
Reliability Assessment	March	May	30 days	
Reliability Solutions	May	July		
Economic assessment	February	May	30 days	
Economic Solutions	May	August		
Policy Assessment	May	August	30 days	
Policy Solutions	May	August		
Stability Assessment	October	December		
Project Grouping	August	September	1 week	
Consolidate Projects	September	October		Oct 27/2014
Project Staging	October	November		Nov 20/2014
Draft Report	July	December	3 weeks	Dec 11/2014
Final Assessment	November	December		Dec 11/2014
Benefit Calculation	November	December	3 weeks	
Refinements and MOPC Presentation	November	January ’15		

2013

2014

RCAR II Schedule

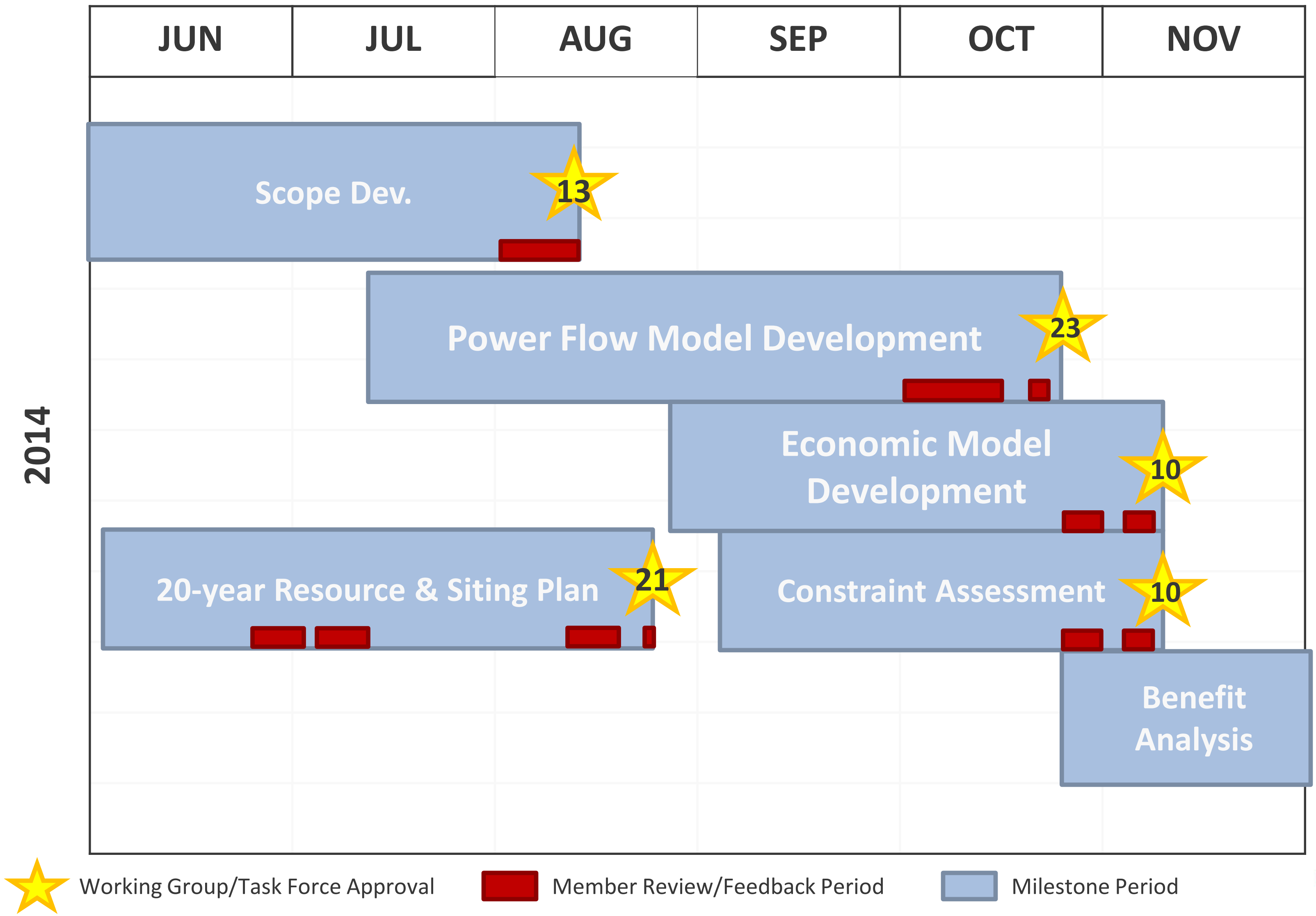
October 23rd, 2014

ESWG

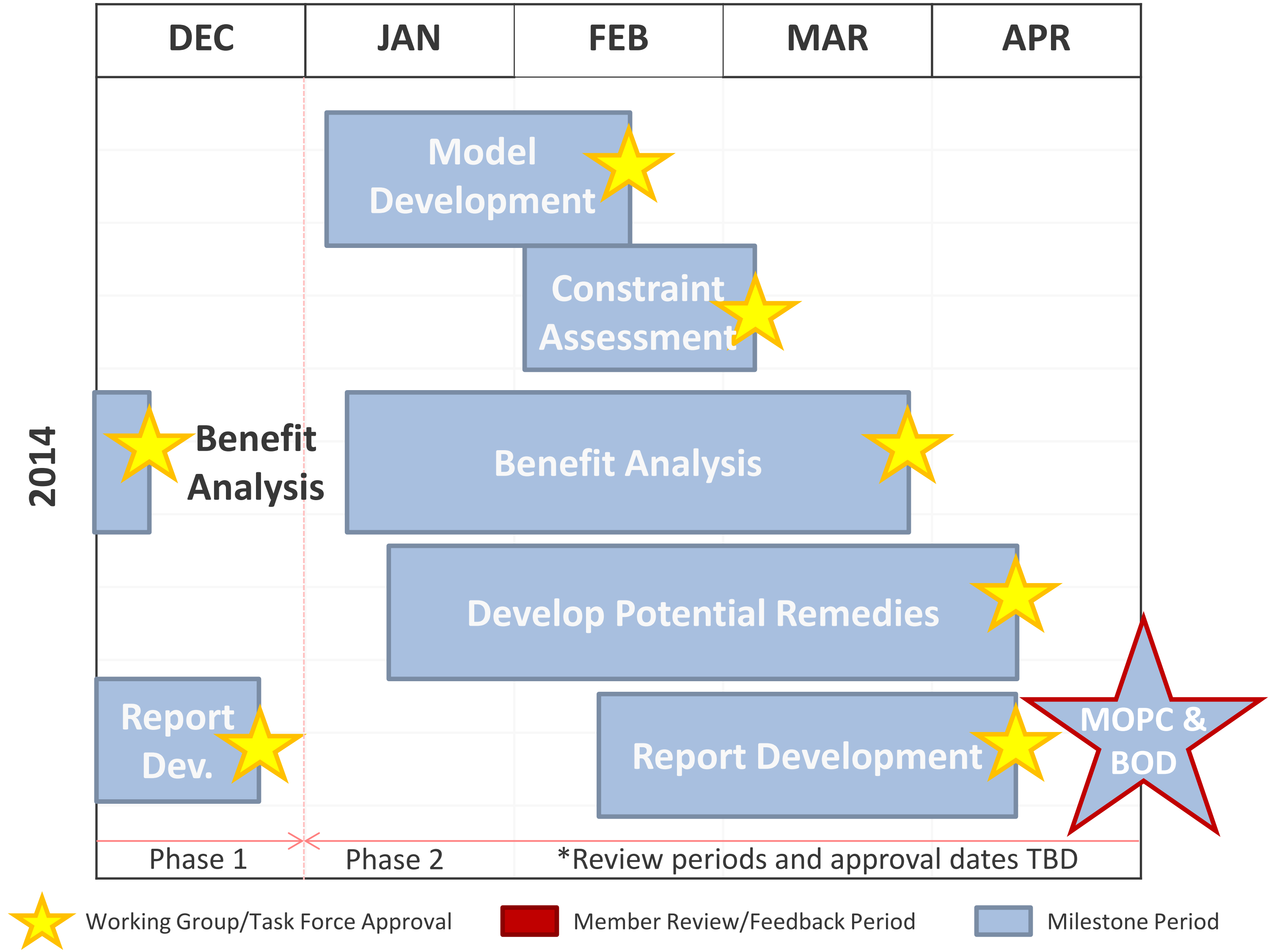
Juliano Freitas

Southwest Power Pool

RCAR II Milestone Schedule (May-Oct 2014)



RCAR II Milestone Schedule (Nov 2014-Apr 2015)



2015 ESWG Meeting Schedule

October 23rd, 2014

SPP Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future

Purpose

- Review proposed ESWG meeting schedule for 2015

Proposed Schedule – 1st Semester

January						
S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28	29	30	31

April						
S	M	T	W	T	F	S
			1	2	3	4
5	6	7	8	9	10	11
12	13	14	15	16	17	18
19	20	21	22	23	24	25
26	27	28	29	30		

February						
S	M	T	W	T	F	S
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28

May						
S	M	T	W	T	F	S
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21	22	23
24	25	26	27	28	29	30
31						

March						
S	M	T	W	T	F	S
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30	31				

June						
S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29	30				

Jan 15th	Dallas
Feb 19th	San Antonio
Mar 10th	Dallas
Apr 9th	Dallas
May 21st	Oklahoma City
June 9th	Dallas

TWG F-F	
Feb 17th	San Antonio
May 19th	Oklahoma City

BOD	CAWG	SSC	
RSC	TWG	GWG	
MOPC	ESWG		
PCWG	MDWG		
SPCWG	SPP Holiday		

Combination Dates

- SSC/PCWG
- TWG/PCWG
- ESWG/MDWG
- SSC/CAWG
- ESWG/TWG

Proposed Schedule – 2nd Semester

July						
S	M	T	W	T	F	S
			1	2	3	4
5	6	7	8	9	10	11
12	13	14	15	16	17	18
19	20	21	22	23	24	25
26	27	28	29	30	31	

October						
S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28	29	30	31

August						
S	M	T	W	T	F	S
						1
2	3	4	5	6	7	8
9	10	11	12	13	14	15
16	17	18	19	20	21	22
23	24	25	26	27	28	29
30	31					

November						
S	M	T	W	T	F	S
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30					

September						
S	M	T	W	T	F	S
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30			

December						
S	M	T	W	T	F	S
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30	31		

Jul 23rd	Dallas
Aug 20th	Denver
Sep 15th	Dallas
Oct 15th	Dallas
Nov 19th	Little Rock
Dec 8th	Dallas

TWG F-F	
Aug 18th	Denver
Nov 17th	Little Rock

- BOD
- RSC
- MOPC
- PCWG
- SPCWG
- CAWG
- TWG
- ESWG
- MDWG
- SPP Holiday
- SSC
- GWG

Combination Dates
- SSC/PCWG
- TWG/PCWG
- ESWG/MDWG
- SSC/CAWG
- ESWG/TWG

2015 ITP10 Report: Part 2

October 23rd, 2014

Amber Greb

Southwest Power Pool

2015 ITP10 Report Sections

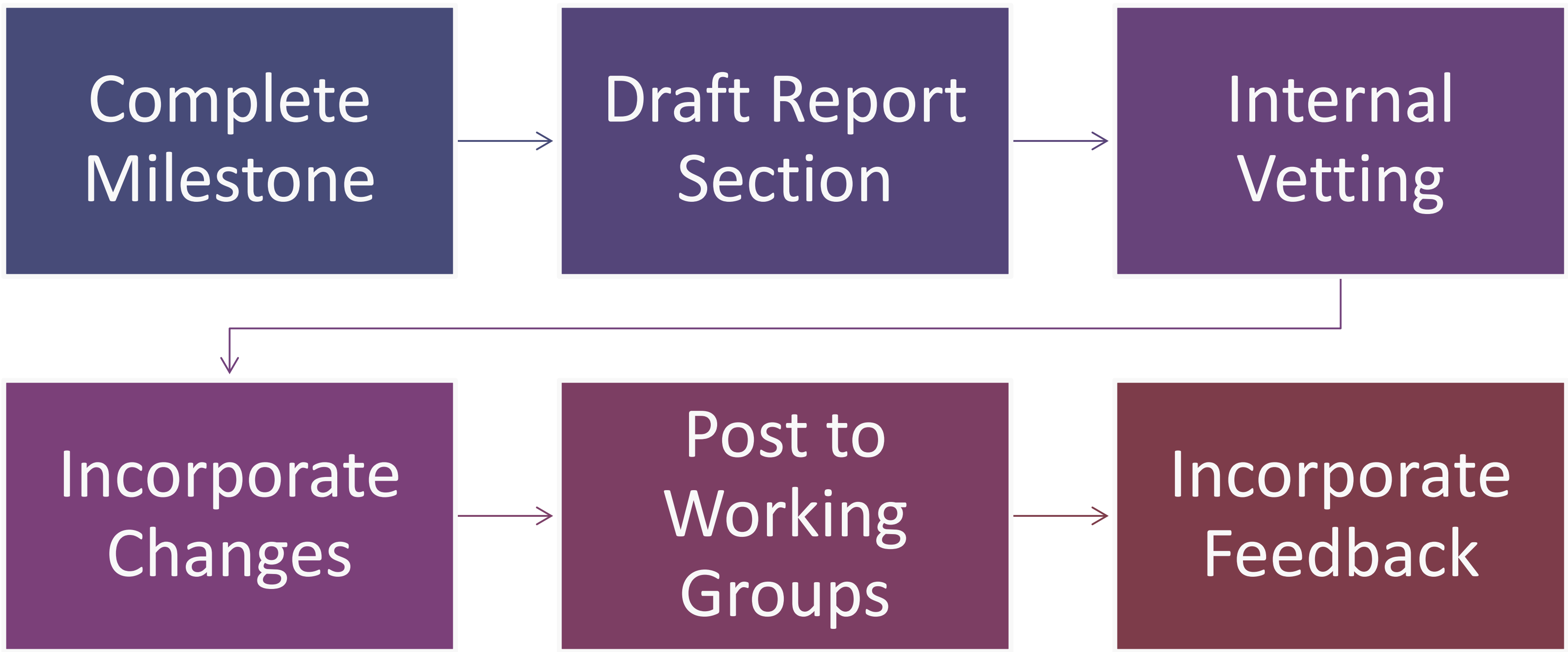
- Scenarios
- **Analysis**
- Results

2015 ITP10 Report Part 2: Analysis

Includes:

- Analysis Methodology
- Benchmarking
- Reliability Needs & Solutions
- Policy Needs & Solutions
- Economic Needs & Solutions

Report Process



Risks/ Mitigation

- Risk – Schedule delays into November
  - Staging (November 20th)
  - Stability Assessment
  - Final Assessment (December 11th)
  - Benefits (December 11th)
  - Sensitivity Analysis
- Mitigation
  - December 11th draft report posting including milestone process only
  - Mid-December posting including milestone process and results

Details

- Report posted in word and pdf
- Open Discussion at WG meeting
- Feedback required as redlines in word document
- 2 week window for Working Group feedback

Contact Amber Greb

agreb@spp.org

Key Dates

Report Section	Posting Date	ESWG Feedback Due
Part 1: Scenarios	July 7	July 21
Part 2: Analysis	**October 23**	**November 6**
Part 3: Results	December 11	December 23
Final Report	January 2	

Section 1:Analysis Methodology

1.1: Analytical Approaches

SPP transmission system performance was assessed from different perspectives designed to identify transmission expansion projects necessary to accomplish the reliability, policy, and economic objectives of the SPP Regional Transmission Organization (RTO). The six perspectives ensured that the transmission expansion portfolio would:

- Avoid exposure to Category A (system intact) and B (single contingency) SPP standard criteria violations during the operation of the system under high stresses;
- Facilitate the use of renewable energy sources as required by policy mandates and goals; and
- Reduce congestion and increase opportunities for competition within the SPP Integrated Marketplace.

Priority was given to the relief of all of the potential reliability violations seen during two unique system stressing hours (summer peak, light load) and to meet all state renewable policy mandates and goals. The relief of annual congestion and reduction in market prices were pursued where cost-justified. A transmission expansion project was considered cost-justified when it yielded a one-year benefit-to-cost ratio of at least 0.9. In some cases, there was overlap among these priorities. For example, a project may relieve potential reliability violations and reduce annual congestion in a cost-justified manner.

SCUC & SCED Analysis for multiple futures

An assessment was conducted to develop a list of constraints for use in the Security Constrained Unit Commitment and Economic Dispatch (SCUC & SCED) analysis. Elements that, under contingency, limit the incremental transfer of power throughout the system were identified, reviewed, and approved by the Transmission Working Group (TWG). Revisions to the constraint definition studies included modification of the contingency definition based upon terminal equipment, normal and emergency rating changes, and removal of invalid contingencies from the constraint definition.

The constraint list included normal and emergency ratings and was limited to the following types of issues:

- System Intact and N-1 situations[1]
- Existing common right-of way and tower contingencies for 100+ kV facilities[2]
- Thermal loading and voltage stability interfaces
- Contingencies of 100+ kV voltages transmission lines
- Contingencies of transformers with a 100+ kV voltage winding
- Monitored facilities of 100+kV voltages only

Neighboring areas supplied their respective list of constraints.

All system needs were identified through the use of a SCUC & SCED simulation that accounted for 8,784 hours representing each hour of the year 2024. AC models were developed from two unique system stressing hours of this simulation to determine reliability thermal and voltage needs.

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[1] N-1 criterion describes the impact to the system if one element in the system fails or goes out of service

[2] The current NERC Standard TPL-001-0.1 includes outages of any two circuits of a multiple circuit tower line within Category C, and the loss of all transmission lines on a common right-of-way within category D. NERC Standard TPL-001-4 will replace this standard (pending FERC approval) and includes such outages in Planning event P7 and Table 1 – Steady State & Stability Performance Extreme Events.

Utilization of Past Studies & Stakeholder Expertise for Solutions

SPP shared potential violations with the stakeholders and interested parties for review. The 2015 ITP10 followed the SPP competitive requirements of the FERC Order 1000 process. SPP staff collected potential solutions from stakeholders throughout the footprint, as well as entities outside of the footprint. A Detailed Project Proposal (DPP) window was opened which allowed any registered transmission company to submit a competitive project proposal to address any need on the SPP system. SPP also collected and analyzed non-competitive solutions under the FERC Order 890 process, as well as developing projects internally and considering solutions previously identified in past Planning Studies[3]. All of these potential solutions were evaluated for their own merits.

Treatment of Individual Projects & Groupings

After assessment of the needs, SPP investigated mitigation of the needs through individual projects by performing the following actions:

- Tested to ensure the project provided the expected result.
- Measured the impact of the projects upon similar constraints and overloads.
- Identified projects with synergy and that duplicated the value captured by another project. Combined reliability, policy, and economic analysis to produce a transmission expansion portfolio of projects.

1.2: Projecting Potential Criteria Violations

Reliability Needs

Two hours that represent situations that uniquely stress the grid were identified to perform a reliability assessment of the System.

- Summer peak (July 19, 5pm) – highest coincident load during summer months
- Light load (April 6, 4am) – highest ratio of wind output to coincident load

AC models were developed for each of the two hours in each future. An N-1 contingency scan was performed for the SPP, Integrated System, and Tier 1 footprints to determine thermal and voltage criteria violations, defined as system reliability needs.

1.3: Meeting Policy Requirements

For policy requirements, staff focused on satisfying statutory/regulatory renewable mandates and goals within a future through use of renewable generation as defined by the SPP Members through the 2014 Policy Survey. Each mandate or goal can be defined as a capacity or energy requirement. The primary generation technology required to meet these renewable standards, as provided by the stakeholders, was wind generation.

Renewable capacity requirements were met with installation of new generating capacity. Renewable energy requirements were analyzed through simulation of the study year. Renewable generation may experience the effects of congestion and be curtailed by the SCED. Shortfalls in the achievement of the renewable requirements of each future due to this curtailment were identified. Companies within each state that experienced an annual renewable energy output less than required were identified as having a policy need.

[3] ITP Near-Term, ITP10, ITP20, Transmission Service Studies, Generation Interconnection Studies, High Priority Studies, Coordinated System Planning Studies.

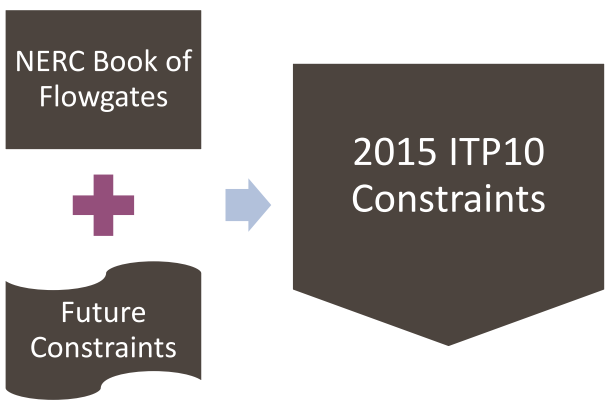
1.4: Projecting Congestion & Market Prices

Annual Conditions Reviewed by the Economic Studies Working Group (ESWG)
Congestion was assessed on an annual basis for each future including many variables. Some of these variables change on an hourly basis, such as load demand, wind generation, forced outages of generating plants, and maintenance outages of generating plants. A total of 8,784 hours were evaluated for the year 2024.

Relevant congestion of each constraint was identified through two methods:

- The number of hours congested, and the average shadow price[4] associated with the congestion for all binding hours.
- These two numbers were multiplied together to compute an average congestion cost across all hours of the year.
- This average congestion cost was used to rank the severity of the congestion for each constraint.

Identification of Additional Constraints
Staff defined the initial list of constraints from the 2013 NERC Book of Flowgates for the SPP, IS, and neighboring regions. Additional constraints were incorporated that would protect the facilities from overloads under many system conditions. These additional constraints facilitated the capture of both market congestion and economic benefit in expectation of transmission expansion that is not anticipated by the NERC Book of Flowgates.



1.5: Determining Recommended Portfolio

Individual projects within the recommended portfolio provided reliability, economic, and policy benefits within the business as usual future (Future 1). Projects meeting the performance criteria for Future 1 *and* Future 2, outlined in Table 6.1, were included in the recommended portfolio.

Project Type	Future 1 Performance	Future 2 Performance
F1 Reliability	Mitigate a thermal or voltage violation	N/A

[4] The "Shadow Price" refers to the savings in congestion costs if the constraint limit in question were increased by 1 MW.

F2 Reliability	Mitigate 90% thermal or 0.92 pu voltage limit	Mitigate thermal or voltage violation
F1 Policy	Meet a policy need	N/A
F2 Policy	N/A	N/A
F1 Economic	1-year B/C ≥ 0.9	N/A
F2 Economic	1-year B/C ≥ 0.7	1-year B/C ≥ 0.9

Table 6.1: Consolidation Criteria

Projects mitigating more than one type of need were evaluated against multiple performance criteria. Only one set of criteria is required to be met for a project to be included in the recommended portfolio.

Project Staging

Project staging is the process by which appropriate need dates for new projects are established. Projects in the 2015 ITP10 were staged based on need and/or performance in the staging year, 2019, when compared to the study year, 2024. The result of this analysis is an interpolated need date for each project of the recommended portfolio, between or equal to the study or staging year.

1.6: Measuring Economic Value

Monetized metrics are used to measure the value of and facilitate better understanding of the financial impacts of proposed projects. The ESWG chose the metrics in Table 6.2 to analyze the recommended portfolio in each Future.

Metric Description
APC Savings
Savings Due to Lower Ancillary Service Needs and Production Costs
Avoided or Delayed Reliability Projects
Marginal Energy Losses
Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
Reduction of Emissions Rates and Values
Public Policy Benefits
Assumed Benefit of Mandated Reliability Projects
Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues

Table 6.2: Monetized Cost Benefit Metrics for 2015 ITP10

While APC benefits were calculated for numerous projects and the final portfolio, the other metrics were calculated only for the final portfolio in each future.

PART II: STUDY FINDINGS

Section 2:Benchmarking

Numerous benchmarks were conducted to ensure the accuracy of the data, including:

1. A model parallel to the study model that reflected transmission and generation in-service as of 2013
2. A comparative of simulation results from the 2013 model with historical statistics and measurements from SPP Operations, SPP Market Monitoring (MMU), and the U.S. Energy Information Administration (EIA).

2.1: Benchmarking Setup

It was important to create a representation of the system as closely as possible to actual operations in 2013. This depiction of the system also had to keep a lineation with the study model, to ensure confidence in the final results.

SPP benchmarked simulation data against historical data provided by SPP Operations and SPP MMU. Area LIPs (Locational Imbalance Price), interchange values, and generation outages were among the data points from these departments. It was unreasonable to expect that the simulation runs for the benchmarking model would be congruent with historical operations for the following reasons:

1. In addition to outage-triggering events, such as storms, PROMOD is not able to simulate the market as it was in 2013, and
2. PROMOD replicates the operations of a day-ahead market using a consolidated balancing authority, whereas the market in operation in 2013 was the SPP Energy Imbalance Service (EIS) with 16 separate balancing authorities.

SPP focused more on the shape of price curves, rather than the magnitude of the values. Also, capacity factors by generation type were benchmarked, rather than the magnitude of the generation.

2.2: Generator Operations

Capacity Factor by Unit Type

Comparing capacity factors enables measuring the similarity in planning simulations and historical operations. This benchmark provides a quality control check of differences in modeled outages and assumptions regarding renewable, intermittent resources.

When compared with capacity factors reported to the EIA in 2013, most of the capacity factors fell near the expected values. The availability of the EIA generation data was limited, as November data was the latest data posted on their website. However, the same time frame was used from the PROMOD simulations (7295 hours as opposed to 8760).

Unit Type	2013 EIA Capacity Factor	PROMOD Capacity Factor
Nuclear	76.3%	93.3%
Combined Cycle	36.6%	30.1%
CT Gas	4.1%	6.1%
Coal	69.6%	74.8%
ST Gas	16.4%	7.2%

Generator Maintenance Outages

Generator maintenance outages in the simulations were compared with historical data provided by SPP Operations. These outages have a direct impact on flowgate congestion, system flows, and the economics of following load levels. The curves from the historical data and the PROMOD simulations complemented each other very well in shape and in magnitude.

Operating & Spinning Reserve Adequacy

Operational reserve is an important reliability requirement that is modeled to account for capacity that might be needed in the event of a unit failure. Per SPP Criteria, operating reserves must meet a capacity requirement equal to the largest unit in SPP + 50% of the next largest unit in SPP; at least half of this requirement must be fulfilled by spinning reserve. Figure 7.1shows both parts of this requirement were met and exceeded. The spinning reserve capacity requirement was 826 MW and the total operating reserve capacity requirement was 1,652.5 MW.

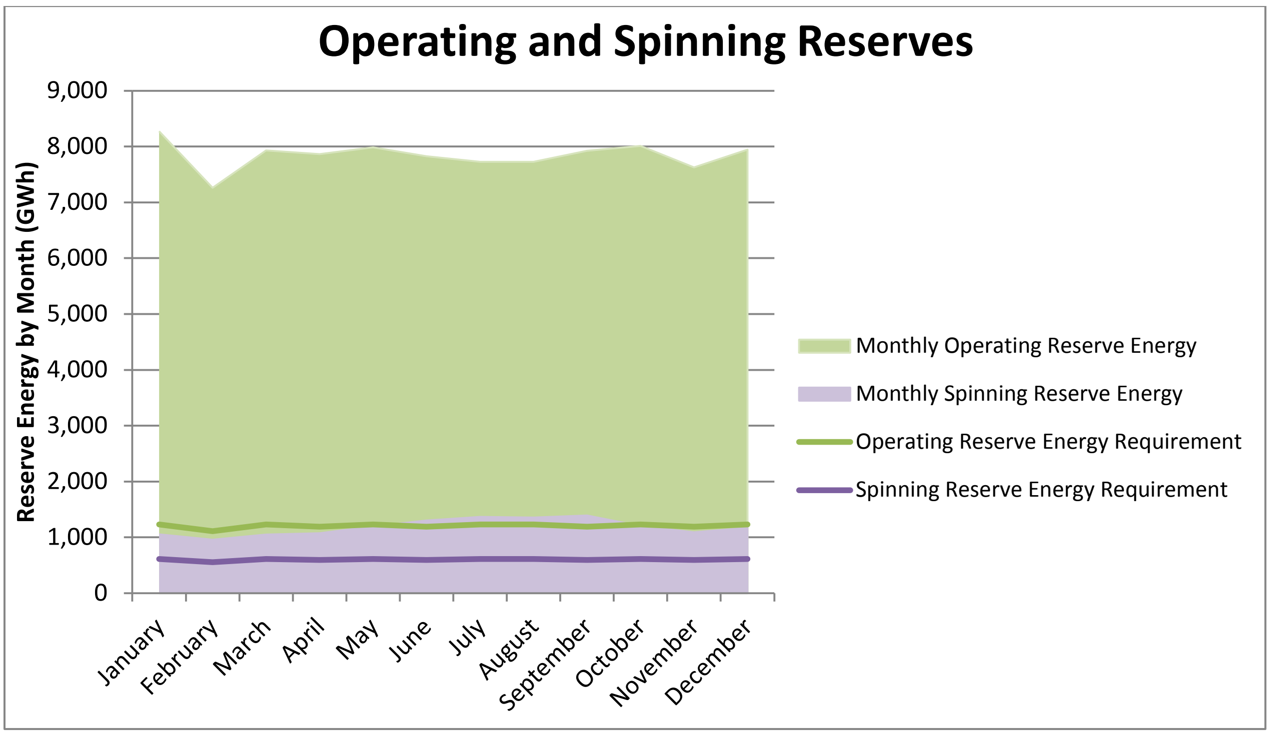


Figure 7.1: Reserve Energy Adequacy

2.3: System LMPs

Simulated locational marginal prices (LMPs) were benchmarked against historical LIPs from SPP Market Monitoring. This data was compared on an average monthly value by area basis. Figure 7.2shows the results of the benchmarking model for the SPP system and the difference in the two curves. Spikes in the summer months were investigated by looking into congestion and other likely drivers. The questionable values were ultimately attributed to the higher volatility of the LMPs in the new market compared to the LIPs of the old.

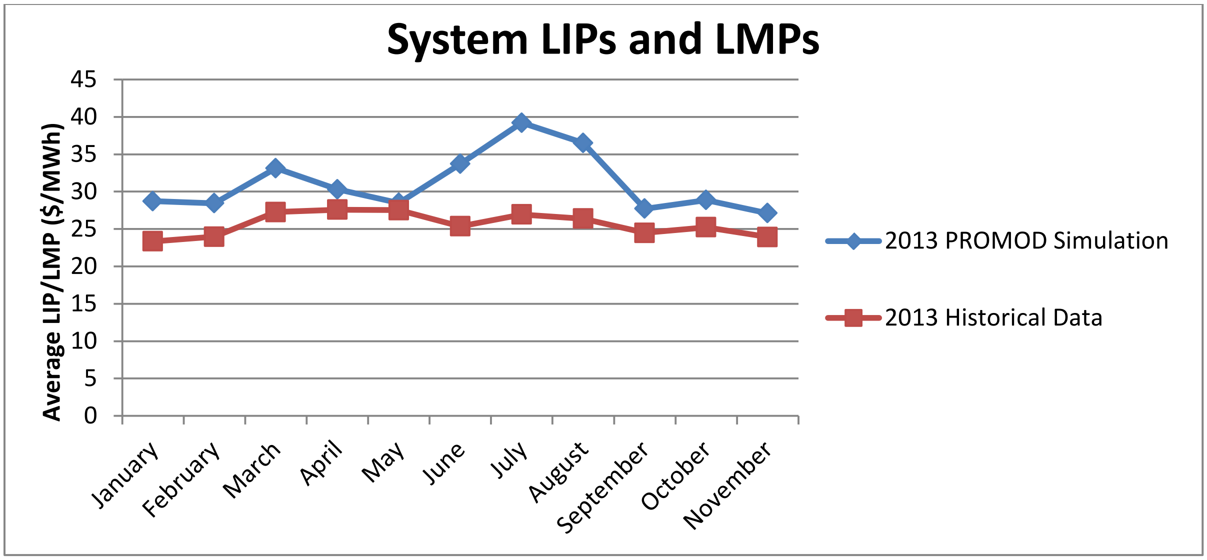


Figure 7.2*: LIP/LMP Benchmarking Results*

2.4: Hurdle Rates

Using hurdle rates between two regions is a modeling technique used to reflect market inefficiencies, such as buying energy outside one's footprint over purchasing native generation. One goal for this ITP study was to find more suitable hurdle rates between SPP and external regions than those used in the past. ITP studies have historically used an $8/MWh commitment hurdle rate and a $5/MWh dispatch rate for all interfaces to and from SPP. With recent enhancements of PROMOD software, defining and testing custom hurdle rates was much easier than how it had been in the past.

Historical tieline flows from SPP Operations were aggregated to total interchange between SPP and each of the Tier 1 pools: the Midcontinent Independent System Operator (MISO), the Mid-Atlantic Power Pathway (MAPP), and the Southeast Electric Reliability Council (SERC). These interchange totals were compared to flows monitored in the PROMOD simulations. Both sets of values were sorted to easily see the differences and similarities of the magnitude of flows and number of hours SPP is exporting to and importing from each region. Hurdle rates were adjusted to and from each region until the most reasonable, optimal results were achieved. Figure 7.3shows this sorted interchange data from SPP Operations and from the final benchmarking simulation results that implemented the ESWG-approved hurdle rates. Hurdle rates between external regions were set to values applied in the 2012 MISO Transmission Expansion Plan (MTEP12) study.

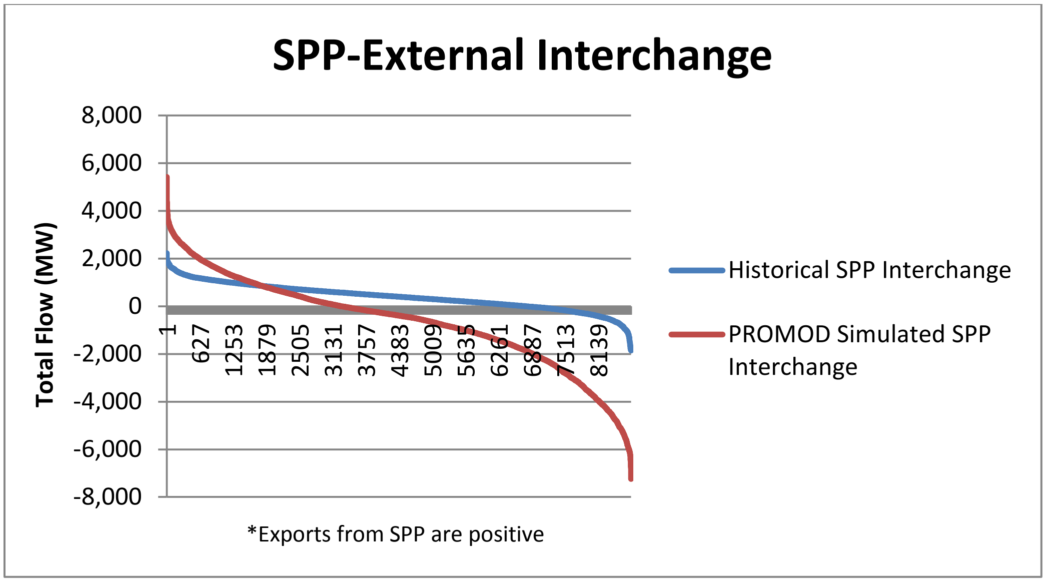


Figure 7.3*: Interchange data comparison*

		To			
		SPP	MISO	MAPP	SERC
From	SPP	*	10/2.5	10/5	10/1.5
	MISO	10/10	*	10/5.5	10/7.4
	MAPP	10/10	10/6.3	*	*
	SERC	10/10	10/8.3	*	*

Table 7.1*: ESWG-Approved Hurdle Rates*

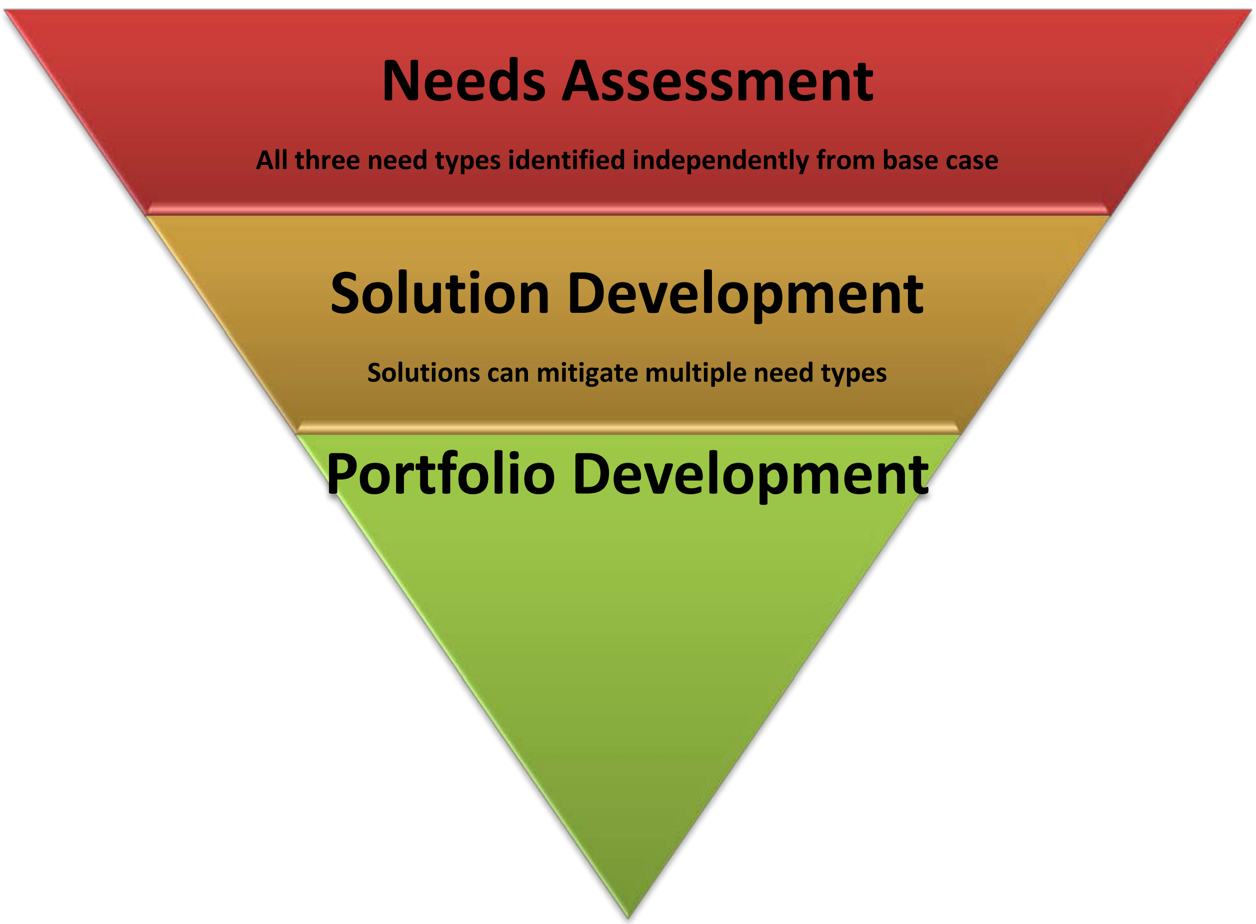
Values displayed are in $/MWh and are reflective of commitment/dispatch hurdle rates

Part III: Needs & Project Solutions

Section 3:Overview

3.1: Transmission Needs and Solution Development

The 2015 ITP10 transmission planning analysis considers three separate types of needs and upgrades: reliability, policy, and economic. Independent of each other, reliability, policy, and economic needs were identified. Solutions were then developed for each need and analyzed individually against the base case. Throughout solution development, projects mitigating multiple needs and/or need types were noted in effort to develop an efficient portfolio. Thus, a single project could mitigate multiple reliability or economic needs or simultaneously mitigate a reliability and economic need. In the 2015 ITP10, no policy needs were identified.



Section 4: Reliability Needs and Solutions

4.1: Methodology

Reliability powerflow models were derived from the economic models through a DC to AC conversion. PROMOD dispatch and load profiles are built in to the powerflow models, which then were used in an AC Contingency Calculation (ACCC) analysis.

Using these powerflow models, reliability needs were identified based on analysis of four hours representing situations where the transmission system is uniquely stressed. The four hours each represent a different future, with Future 1 representing Business as Usual[5] and Future 2 representing a Decreased Base Load Capacity[6]. An N-1 contingency scan outaged 69 kV branches and above in the SPP RTO and First-Tier footprints. Facilities 69 kV and above were monitored to identify needs in the SPP RTO and First-Tier footprints. Potential violations, in accordance with the SPP Criteria or SPP Member criteria if more restrictive, were identified in each of these hours during the N-1 contingency scans and labeled as reliability needs.

Once the reliability needs were identified, the list of needs was filtered based upon exclusions in the reliability assessment criteria.

Hours used to determine reliability needs were:

- **Summer peak hour -** represents the highest coincident load during summer months
- **Light Load hour -** represents the low load and high wind based on a market dispatch

HOUR NAME	HOUR SIMULATED
Future 1 Summer Peak	July 19, 2024 17:00
Future 1 Light Load	April 6, 2024 04:00
Future 2 Summer Peak	July 19, 2024 17:00
Future 2 Light Load	April 6, 2024 04:00

Table 9.1: Future hours analyzed for Reliability needs

4.2: Reliability Needs

The types of reliability needs identified in the 2015 ITP10 consist of thermal overload and under-voltage needs. Any valid thermal overload greater than 100%, voltage violation under 0.95 per unit for basecase

[5] This future included all statutory/regulatory renewable mandates and goals as well as other energy or capacity as identified in the policy survey, load growth projected by load serving entities through the MDWG model development process, and the impacts of existing regulations. This future assumed no major changes to policies that are currently in place.

[6] This future considered factors that could drive a reduction in existing generation. It included all assumptions from the Business as Usual future with a decrease in existing base load generation capacity. This future retired coal units less than 200 MW, reduced hydro capacity 20% across the board, and utilized the Palmer Drought Severity Index for an average of August 1934 and August 2012 to simulate a reduction in existing capacity affected by drought conditions: 10% under moderate, 15% under severe, and 20% under extreme. These target reductions may have been adjusted based on locational and operational characteristics within each zone.

conditions, or under 0.90 per unit[7] for contingency conditions were included as reliability needs. More restrictive needs are considered non-competitive needs and therefore were not included in the final needs list, but were provided to the appropriate SPP member for solution development. Needs that were non-SPP Transmission Facilities near the Tier-1 seams were separated from the final needs list to allow for possible joint analysis to be performed and for possible seams project development.

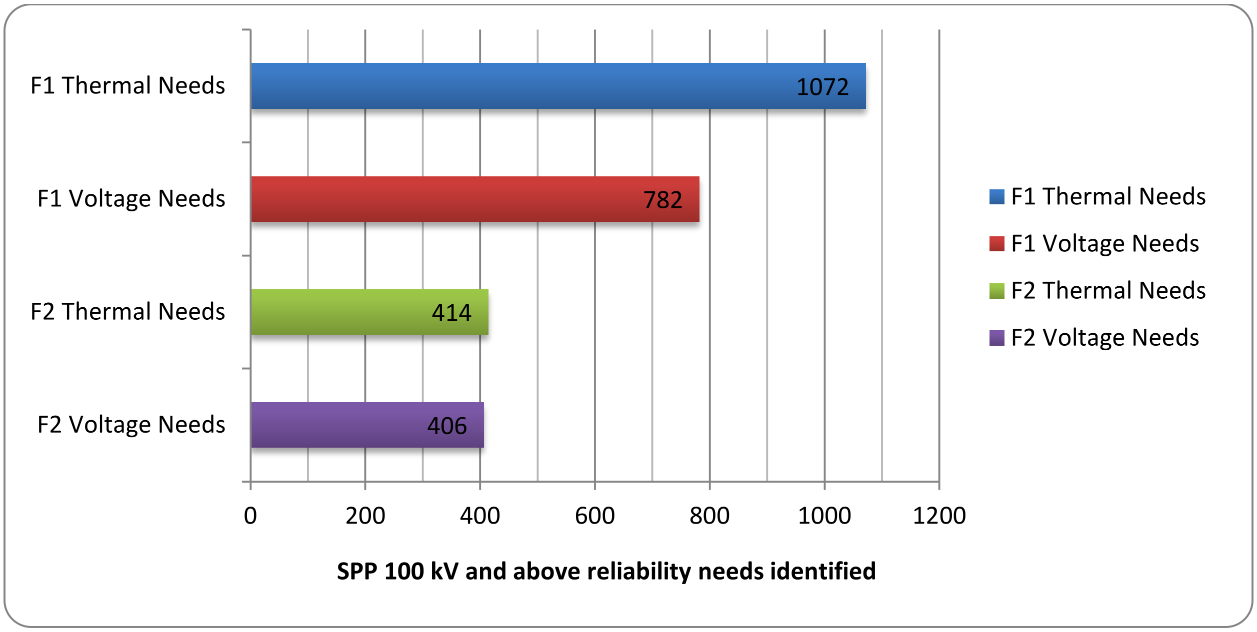


Figure 9.1: Thermal Overload and Voltage Needs Summary by Future

[7] This per unit value is the SPP Criteria voltage per unit threshold for classifying voltage violations under contingency conditions. Voltage violations derived from member submitted criteria that was more restrictive than the SPP Criteria was used in place of the SPP Criteria for needs identification.

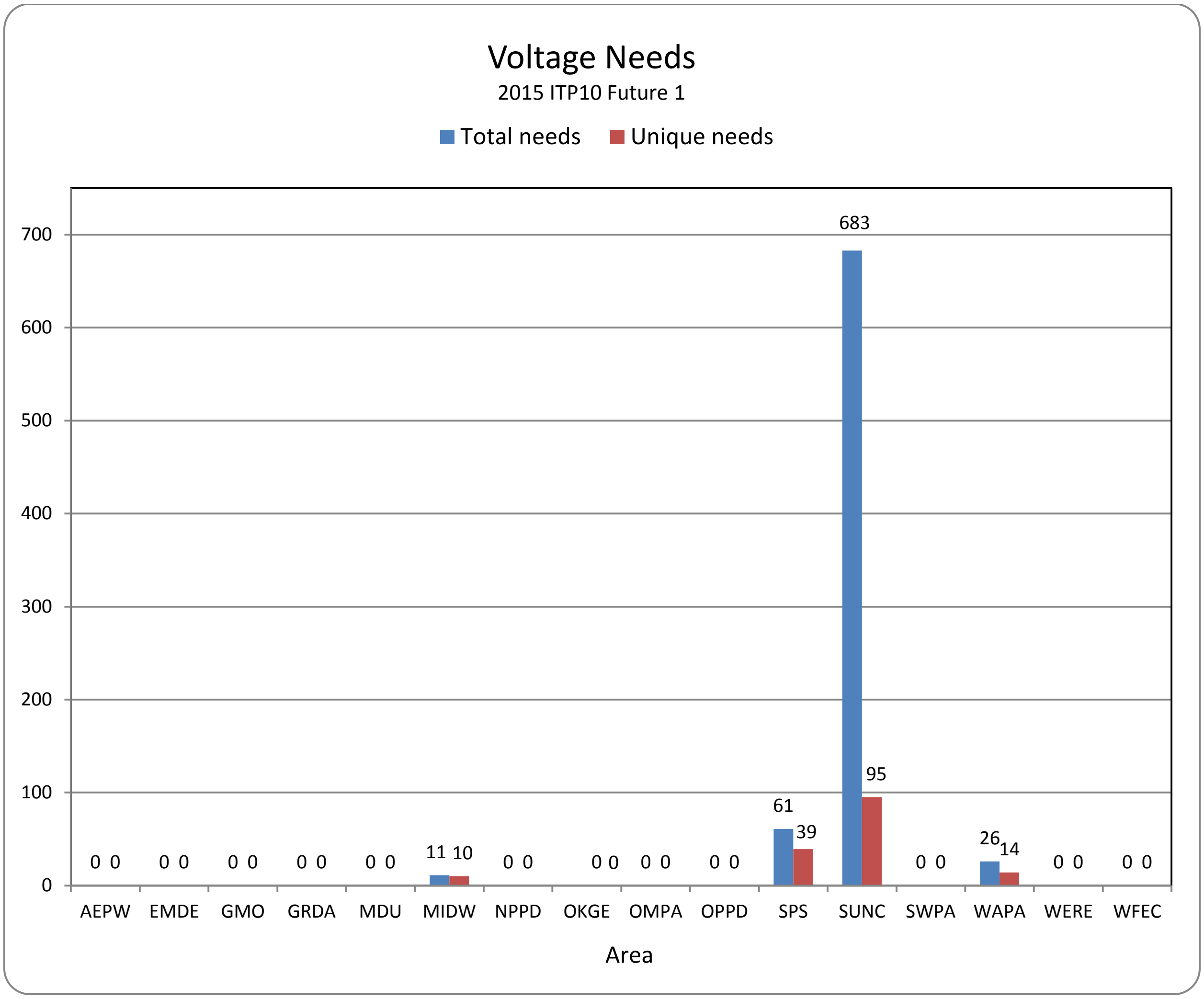


Figure 9.2: Voltage Needs Summary Future 1

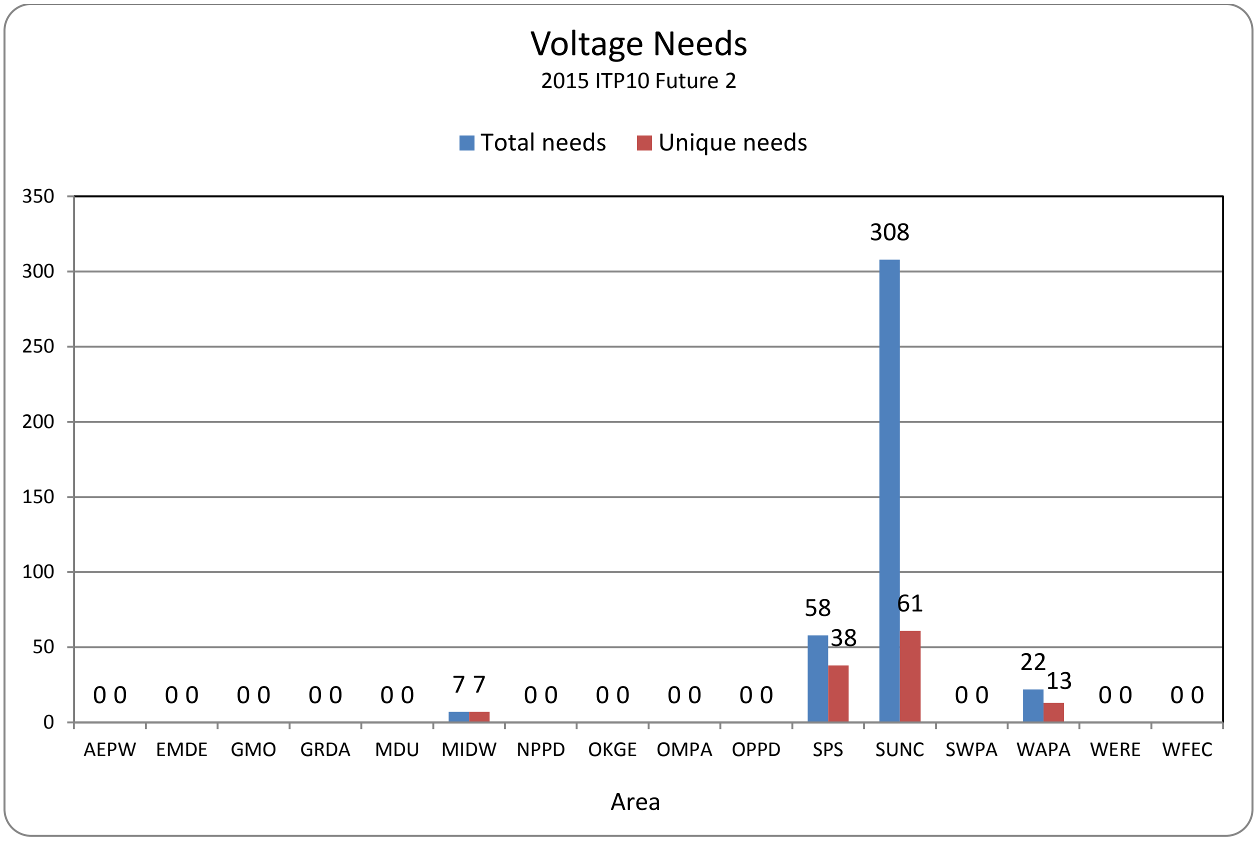


Figure 9.3: Voltage Needs Summary Future 2

4.3: Project Processing Methodology

In order to comply with FERC's Order 1000, SPP developed the Transmission Owner Selection Process to allow competitive bidding on qualifying transmission projects. Transmission Facilities that meet the criteria listed in Attachment Y, Section I.1 of the SPP Tariff and are approved for construction, or are endorsed by the SPP Board of Directors, after January 1, 2015 are known as Competitive Upgrades. A 30 day window was opened with the public posting of the final 2015 ITP10 needs list. During this time any stakeholder had the opportunity to provide one or more Detailed Project Proposals (DPPs), which are considered Competitive Upgrades. If the project described in the DPP is selected and approved for construction as a Competitive Upgrade, then the submitting stakeholder may be eligible to receive incentive points pursuant to the eligibility requirements described in Section III.2.f.iv of the Tariff's Attachment Y.

With the possibility of obtaining incentive points for selected and approved Competitive Upgrades, Stakeholders submitted 1,179 DPPs and 56 Non-Competitive projects. In addition to the DPPs and Non-Competitive projects, SPP created 157 SPP staff solutions to address the reliability needs. All together 1,392 projects were evaluated.

In order to efficiently evaluate the tremendous amount of submitted and created projects that would solve all identified reliability needs within the allotted schedule; a software solution was developed by SPP. This Comprehensive Project Testing tool tested all projects against all reliability needs to determine which needs the projects solved using PSS®E analysis. All automated results were then manually checked for result validation purposes.

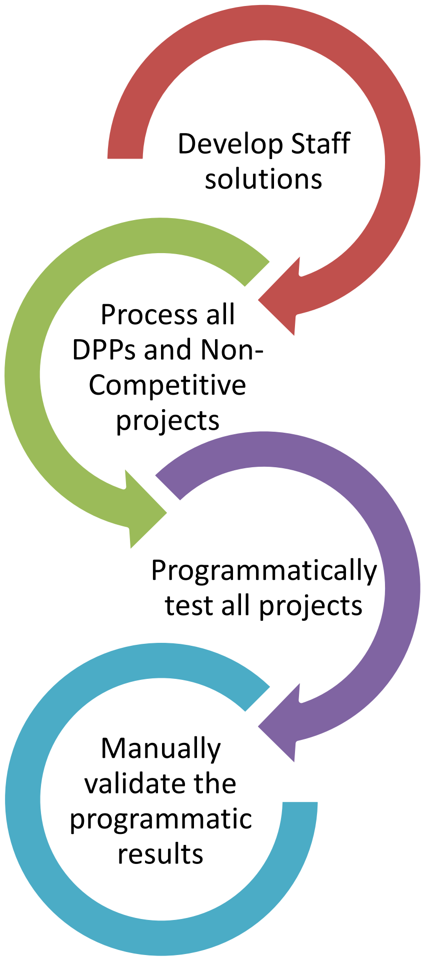


Figure 9.4: Project processing overview

4.4: Project Selection Methodology

SPP staff developed a standardized conceptual cost template for adding project costs to all submitted and SPP staff developed projects. Once all projects were assigned a cost, each project was compared against all other projects using a least cost metric as well as a separate comparison using a cost per need metric. In order to perform a comparison of the copious amount of projects, a programmatic solution was developed by SPP staff. Using this Project Selection software, a subset of projects was generated that solved all reliability needs in the most cost effective manner.

Further engineering analysis of this subset of projects was performed to check the performance of the projects. If a project was selected because it met one or more reliability need(s) and had a lower cost than a similar project, it was further analyzed to compare the amount of loading relief or voltage support it provided versus a similar project that met the same reliability needs.

In looking for robustness of the selected projects, SPP staff checked for projects that were selected in both Future 1 and Future 2. These are the same projects that solved reliability needs identified in Future 1 as well as Future 2.

When SPP staff thought that combining projects could be beneficially from a reliability standpoint, individual projects were combined into a single project and re-evaluated in the project selection process to check if the combined project was selected as the least cost solution while meeting all reliability needs of the individual projects.

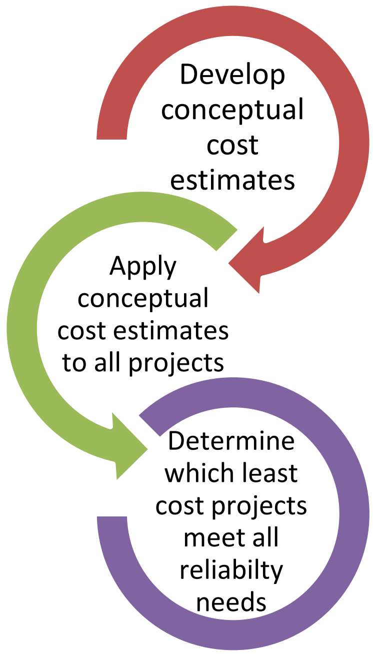
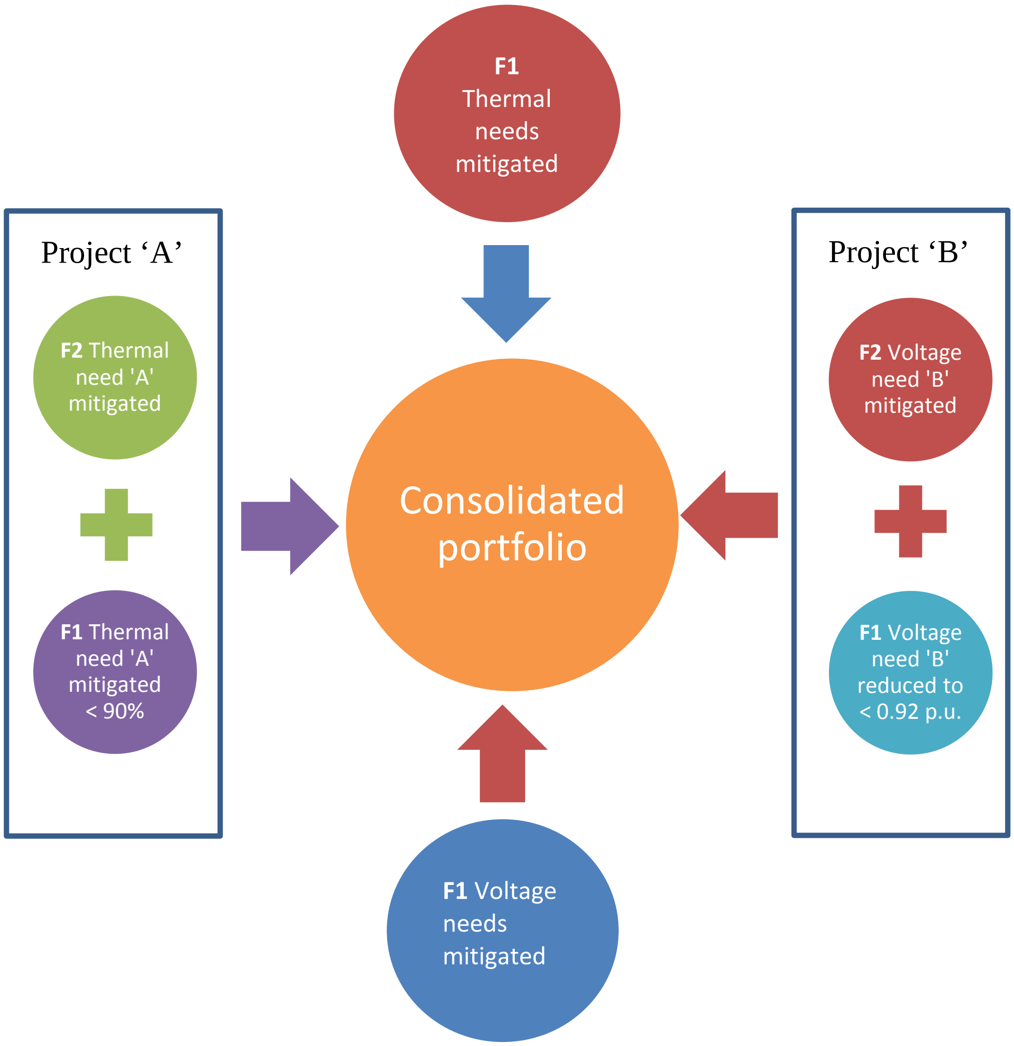


Figure 9.5: Project Selection overview

4.5: Project Grouping Methodology

For the Consolidated Portfolio, the following criteria, as listed in the approved 2015 ITP10 scope allows for grouping of Reliability projects from Future 1 and Future 2:



The Consolidated portfolio mix is made up of XXX Future 1 projects and XXX Future 2 projects.

All projects that comprise the Consolidated portfolio were submitted to an industry-recognized third-party vendor for a fair and unbiased cost estimate for each individual project.

Placeholder

Table 9.2: Future 1 Reliability Needs

Placeholder

Table 9.3: Future 2 Reliability Needs

4.6: Reliability Solutions

Project solutions were developed by stakeholders and SPP staff. 100 kV and above projects were considered as solutions for reliability needs. To test the reliability solutions, a project was added to the model for the hour in which the need occurred. Loading on the constrained element was assessed. The solution was considered valid if the element was no longer binding or breaching the limit. Multiple solutions were considered for many needs, and engineering judgment was used to determine the solution that provided the best fit for the region.

Tables 9.4 through Table 9.5 summarize the reliability project solutions for each future, including the constrained element that is being relieved by each project.

Reliability Project	Project Area(s)	Constrained Element	Miles Added/ Modified

Table 9.4: Future 1 Reliability Solutions

Reliability Project	Project Area(s)	Constrained Element	Miles Added/ Modified

Table 9.5: Future 2 Reliability Solutions

Section 5:Policy Needs and Solutions

5.1: Methodology

Policy needs were analyzed based on the curtailment of renewable energy that has been installed to meet a Renewable Energy Standard (RES) mandate or goal. Each company with a renewable mandate or goal was analyzed for renewable curtailments to see if they meet their mandate or goal. Policy needs are the result of an inability to dispatch renewable generation due to congestion, and any company not meeting their renewable mandate or goal due to such congestion was identified as a policy need.

Renewable mandates and goals by company were determined based on the 2014 Policy Survey. A 3% margin was used in determining the thresholds by company. This means that if a company had an annual renewable energy usage of at least 97% of their Policy Survey mandate or goal, they were identified as meeting renewable requirements, and are not identified as a policy need. Some mandates and goals were installed capacity requirements only; these were not analyzed for curtailment, and are not policy needs.

Policy projects are developed for any policy needs in order to reduce curtailments such that all companies will meet their renewable mandates or goals.

5.2: Policy Needs and Solutions

The policy needs assessment showed the following wind farms have > 3% annual curtailment:

Wind Farm	Owner & State	Future	Annual Curtailment (GWh)	Annual Curtailment %
Gray County	KCPL, MO	F1	29.3	5.64%
Gray County	KCPL, MO	F2	29.3	5.64%
New Mexico #4	SPS, NM	F2	76.9	6.91%

Table 10.1: Wind Farm Curtailment

In spite of these curtailments, all companies met their overall renewable mandates and goals. **Therefore, there are no policy needs and no policy projects in either future.**

Section 6:Economic Needs and Solutions

6.1: Background

The 2015 ITP10 economic needs assessment was performed in parallel with the reliability and policy needs assessments. All needs were based on a single base model. Potential economic projects included those from staff, DPPs, Order 890 submittals, and previous SPP Planning studies were tested individually in this base model. An economic project is justified when its benefits to SPP stakeholders are greater than the cost. Therefore any justified economic project in the 2015 ITP10 must have a minimum 1-year benefit-to-cost (B/C) ratio of 0.9, since the benefit will only increase in its assumed 40-year lifespan. Benefits were measured as the difference in the Adjusted Production Cost (APC) with and without the potential economic project.

6.2: Economic Needs

To assess economic needs, a security constrained unit commitment and economic dispatch (SCUC/SCED) were performed for the full study year, based on the transmission constraints defined for the system. The SCED derived nodal Locational Marginal Prices (LMPs) by dispatching generation economically. LMPs reflect the congestion occurring on the transmission system's binding constraints. The simulation results showed which constraints caused the most congestion, and the additional cost of dispatching around these constraints. The following process was used for each future:

1. Binding constraints were ranked from highest to lowest congestion score. Congestion score is defined as the product of the average shadow price of the constraint and the number of hours the constraint is binding in 2024.

2. The Top 25 most expensive constraints[8] in the SPP system were identified as the economic needs of the system.
3. Potential economic project solutions were developed based on this list of 25 constraints.

[8] This specific criteria was identified in the study scope, prior to analysis of economic needs. The Top 25 binding constraints were chosen to be targeted in order to better understand what parts of the system would be best suited for the testing and development of economic projects. Parts of the system with minimal congestion are less likely to have project solutions with B/C ratios greater than 0.9.

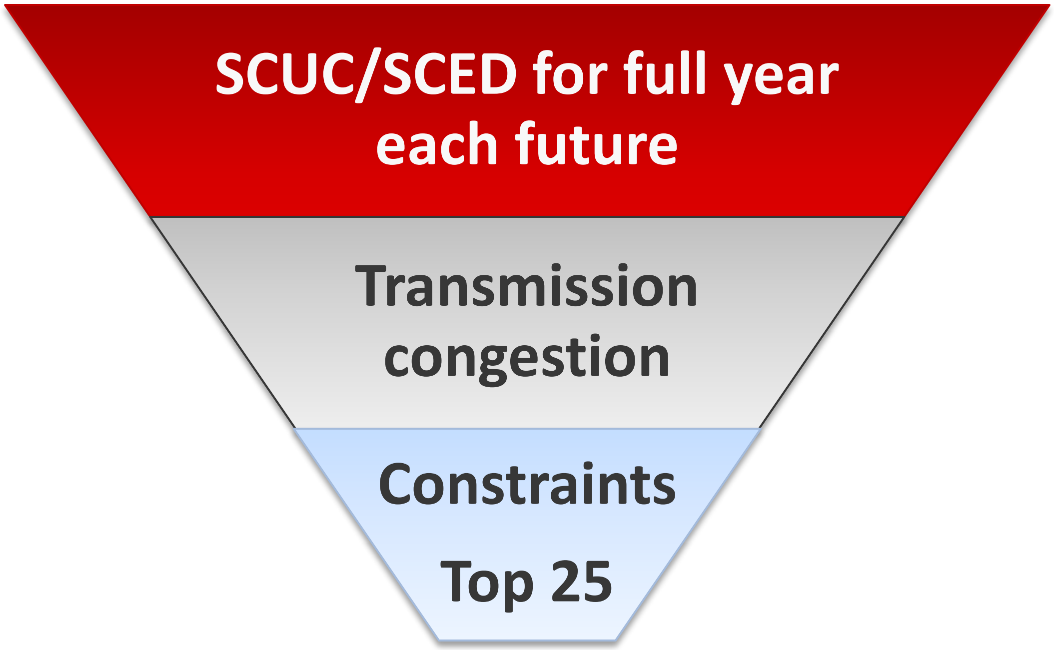


Figure 11.1: Developing Economic Needs

If generation sited from the resource plan was connected to a transformer or branch caused enough congestion at the facility to make it a Top 25 constraint, then that economic need was ignored since the placement of the generator at a different bus in the system could mitigate the need.

Identification of the Top 25 constraints was conducted without the inclusion of any reliability or policy projects in the models. Therefore, some of the Top 25 (shown in the Study Drivers Section) needs that arose could have already been addressed through reliability or policy projects.

6.3: Economic Solutions

Economic projects were proposed based on their potential to mitigate congestion of the Top 25 constraints and stakeholder recommendations. Economic staff solutions, DPPs, Order 890 submittals and projects previously evaluated in SPP Planning studies were evaluated based on a multi-phase process vetted through the ESWG.

For each economic project, the APC for the SPP footprint was calculated with and without the proposed economic project for all 8,784 hours of 2024. The change in APC with the project in-service was considered the one-year benefit. The one-year benefit was divided by the one-year cost of the project to develop a B/C ratio for each project.

In addition to projects targeting the Top 25 constraints, all EHV projects targeting reliability needs were analyzed for economic benefit. No policy needs were identified in the 2015 ITP10, therefore there were no projects that would target a policy need to test for economic benefit.

All 2015 ITP10 economic solutions were evaluated through a number of phases described below. A different cost sharing assumption for any project identified as a potential seams project was discussed and approved by the ESWG. For these projects, it is assumed that SPP will bare 80% of the total cost; all B/C ratio criteria remain the same.

Pre-Phase 1

The intent of this phase was to filter projects prior to PROMOD testing. Before Phase 1, individual projects went through an initial screening to test for reasonableness. The potential annual APC benefit was calculated for each of the economic *needs* by removing each constraint or group of constraints and rerunning the simulation. Based on this calculation, economic projects would move on to Phase 1 for further testing if 75% of the potential APC benefit calculated compared with the estimated 1-year conceptual project cost of a project targeting a particular constraint or group of constraints resulted in a 0.5 1-year B/C ratio or greater.

Due to the complexities of the interaction of constraints and the projects developed to mitigate the congestion experienced by those constraints, at a minimum, all projects targeting economic needs in the 2015 ITP10 were moved on to be evaluated in Phase 1.

Phase 1

Phase 1 considered an individual project's performance in the base case. Projects moved on to Phase 2 for further testing if they provided a 1-year B/C ratio of 0.75 or greater by reducing congestion.

Phase 2

A project's performance, in concert with other potential projects, was considered in Phase 2. Reliability and economic projects were combined into project groupings for each future and evaluated for redundancies. SPP staff first evaluated a group of projects meeting all reliability needs as a portfolio to determine any potential overlap with economic solutions by measuring system congestion relieved by the portfolio. After the reliability projects were evaluated as a group staff developed groupings for economic projects while considering potential redundancies with other project types.

Project groupings were developed based on the projects' performance in Phase 1. Projects for each grouping were selected by ranking the top projects for each need. A project must have provided a reasonable amount of congestion relief (at least 70%) to be considered in the ranking for a particular need. This relief was based on percent mitigation of flowgate congestion cost. A project selected for a particular need may also provide a certain amount of congestion relief for another need. This overlap was evaluated to determine the mos appropriate project(s) for the needs met. Not all economic needs had a project selected. Four groupings were considered per future:

- Cost-Effective – This group included projects that met the study need in the most cost-effective way. If one project mitigates multiple needs, the cost of that project was compared to the cost of one or more projects mitigating that same group of needs.
- Highest Gross APC Benefit – This grouping consisted of the projects that met the needs with the highest APC benefit. This grouping did not consider the cost of the projects.
- Highest Net APC Benefit – This group included the projects that met the needs of each future with the highest net APC benefit. The cost of each project was subtracted from the APC benefit provided to determine the project's net APC benefit.
- Multi-Variable Grouping – This optional grouping was proposed to allow SPP staff to layer multiple criteria to form an additional group for testing. The experience gained from analyzing projects for the first three groups was to be utilized to determine projects included in this grouping. This grouping was not developed.

The grouping with the highest net APC benefit moved on for further analysis; the groupings that moved on were the Highest Net APC Benefit groupings for both futures.

The projects in the selected grouping were tested individually against the Phase 2 B/C criteria, 1-year B/C of 0.9 or greater If any project did not meet the threshold, it was removed from the portfolio. Replacement projects were evaluated from the pool of ranked projects. Regardless of whether a viable replacement project was found, each project from the portfolio was retested against the Phase 2 criteria. This analysis continued iteratively until a final portfolio per future was determined.

Phase 3

The goal of Phase 3 was to consolidate both of the Phase 2 groupings into one final portfolio. Future 1 economic projects with a 1-year B/C ratio greater than 0.9 in Future 1 were included in the consolidated portfolio. Future 2 economic projects with a 1-year B/C ratio greater than 0.9 in Future 2, but that also have a 1-year B/C ratio greater than 0.7 in Future 1 were also included in the consolidated portfolio.

6.4: Economic Groupings

Future 1 Economic Projects

Table 11.1 shows the economic projects that were included in the final Future 1 grouping at the end of Phase 2. When testing projects that were not already included as reliability projects, all reliability projects were included in the base and change cases. When testing the economic value of projects that were previously identified as reliability or policy projects, the base case included all reliability projects minus the project under test, while the change case included all reliability projects including the project under test. Reliability projects were included in the base and change cases in order to provide a more conservative approach to calculating their benefit; if the reliability projects are expected to be built in the 20-year horizon, the benefit of economic projects for that time frame should be measured with these already in the model.

One Future 1 reliability project is also an economic project. Its primary classification going forward is as an economic project.

Economic Project	Project Area(s)	Constrained Element	Miles Added/ Modified	One Year B/C
New Chamber Springs - S Fayetteville 345 kV, new S Fayetteville 345/161 kV transformer	AEPW	Farmington - Chamber Springs 161 kV	18	3.73
New Wolf Creek - Neosho 345 kV	WERE	Morgan - Stockton 161 kV, Litchfield - Franklin 161 kV, Centennial - Paola 161 kV	99	1.41
New 2nd S3459 345/161 kV transformer	OPPD	S1221 - S1255 161 kV	0	27.76

Table 11.1: Future 1 Economic Grouping

Future 2 Economic Projects

Table 11.2 shows the economic projects that were included in the final Future 2 grouping at the end of Phase 2. Most of the Top 25 economic needs in Future 2 were addressed by reliability and policy projects.

Two Future 2 reliability projects were also considered economic projects.

Placeholder

Project Tested	Project Area(s)	B/C > 1.0?
New Morgan 345/161 kV transformer	AECI	✗
New Tolk - Amoco 345 kV	SPS	✗
New Amoco - New Deal 345 kV	SPS	✗

Table 11.2: Future 2 Economic Grouping

NERC Probabilistic Assessment Final Report

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Modeling

SPP Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future

Results

MRA metrics results		
SPP Region	2016	2018
Forecast Planning Reserve Margin (%)	26.9%	24.4%
Forecast Operable Reserve Margin (%)	23.4%	21.3%
LOLE (days/year)	0	0
LOLH (hours/year)	0	0
EUE (MWh/year)	0	0
EUE (Normalized MWh/year)	0	0

Schedule

October 23rd, 2014	Final draft to ESWG
November 3rd, 2014	Final draft to NERC
January 6th, 2015	Draft report submission to RAS – ProbA team
January 23rd, 2015	Draft report submission to RAS
February 13th, 2015	Draft report to PC
March 3rd, 2015	PC approval of final report

Recommendation

- **SPP staff recommends the approval of the 2014 Probabilistic Assessment final report**

Are there any questions?

2014 Probabilistic Assessment

03NOV14
SPP Modeling

Southwest Power Pool

Table of Contents

Table of Contents **1**

1. Summary 3
   a. Identification of entities included in MRA 4
   b. Seasonal capacity totals 5
   c. Coincident forecast 50/50 peak seasonal demands 6
   d. Net Energy for Load 6
   e. MRA metrics results 6
   f. Study Results 7
2. Software model description 8
   a. Computational approach 8
   b. Algorithm usage 9
   c. Tiered simulation 9
   d. External area modeling 9
3. Demand Modeling 9
   a. Explanation of differences between reported data and LTRA 9
   b. Explanation of chronological load model and loads accounted for out of region 10
   c. Explanation of how load forecast uncertainty was modeled 10
   d. Explanation of how behind-the-meter generation was modeled 12
4. Controllable Capacity Demand Response Modeling 12
   a. Explanation of how controllable capacity demand is modeled 12
5. Capacity Modeling 12
   a. Difference between the MRA and LTRA capacities 12
   b. Determination of whether “Future, Planned” generation is “firm and deliverable 12
   c. Explanation of how jointly owned units are modeled 12
   d. Capacity sales and purchases 13
   e. DC Ties 13
   f. Intermittent and energy-limited variable resources 13
   g. Traditional dispatchable capacity 13

6. Transmission 14
a. Transmission additions and retirements 14
b. MRA's transmission modeling approach 14
7. Assistance from External Resources 14
a. Quantifying non-firm assistance from resources outside of the MRA's footprint 14
8. Definition of Loss-of-Load Event 15
a. MRA's definition of loss-of-load event 15
9. Scenario Modeling 15
a. Scenario Simulation 15

1. Summary

The Southwest Power Pool (SPP) 2014 Probabilistic Assessment is a mandatory study requested by North American Electric Reliability Corporation (NERC), under the guidance of the Reliability Assessment Subcommittee (RAS). The objective of this assessment is to provide a common set of probabilistic reliability indices and recommend probabilistic-based work products that could be used to supplement NERC's Long-Term Reliability Assessments (LTRA). The terminology of Metrics Reporting Areas (MRA) for this report is synonymous with the reporting subregions of the LTRA. This study is based on the 2014 LTRA data, which included entities in the SPP Planning Coordinator (PC) footprint.

SPP used GridView version 9.1.12, an ABB application, to perform the probabilistic analysis of the 2014 LTRA data for study years 3 and 5, 2016 and 2018, respectively. Three metric results were calculated in this study: annual Loss of Load Hours (LOLH), Expected Unserved Energy (EUE), and Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE). For the purposes of the SPP Criteria, the LOLE in days/year will also be provided.

The final report from the 2014 Probabilistic Assessment, upon endorsement by the Economic Studies Working Group (ESWG), will be submitted to NERC on Nov. 3, 2014. The NERC Probabilistic Assessment and LOLE Capacity Margin assessments will continue to be performed at least on a biennial basis by SPP. The next Probabilistic Assessment cycle will be in 2016.

a. Identification of entities included in MRA

Sixteen entities (geographic subregions) were modeled within the SPP PC footprint. The SPP PC footprint includes all or parts of Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, Texas, and Nebraska.

MRA geographic subregions for the 2014 Probabilistic Assessment

AEPW [1,2]	American Electric Power West
EMDE	Empire District Electric Company
GRDA	Grand River Dam Authority
INDN	Independence Power & Light Department
BPU	Board of Public Utilities, Kansas City, Kansas
KCPL	Kansas City Power & Light Company
LES	Lincoln Electric System
GMO (MPS)	Greater Missouri Operations Company
NPPD	Nebraska Public Power District
OKGE	Oklahoma Gas and Electric Company
OPPD	Omaha Public Power District
SPS	Southwestern Public Service Company
SUNC (SEPC)	Sunflower Electric Cooperative
SWPA [3]	Southwestern Power Administration
WERE [4]	Westar Energy, Incorporated
WFEC	Western Farmers Electric Cooperative

[1] FERC 714 Hourly Load data for AECC is reported through AEPW, OKGE, and SWPA.
[2] FERC 714 Hourly Load data for OMPA is reported through AEPW, OKGE, and WFEC.
[3] FERC 714 Hourly Load data for SPMR is reported in SWPA through 2010. 2011 SPRM Hourly Load data was added to SWPA numbers to create the Load Uncertainty Model.
[4] FERC 714 Hourly Load data for MIDW is reported through WERE.

b. Seasonal capacity totals

Capacity data modeled in this assessment was derived from the 2014 LTRA. The table below summarizes the makeup of the capacity categories and amounts used in the assessment by study year (2016, 2018). Differences in capacity values between this assessment and the 2014 SPP LTRA report are discussed in section 5a.

Seasonal capacity totals

Category	2016		2018	
	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
Demand-Side Management-Available	937	937	797	797
On-Peak Expected Capacity (Coal)	24,431	24,431	24,680	24,680
On-Peak Expected Capacity (Gas)	29,547	29,547	29,623	29,623
On-Peak Expected Capacity (Hydro)	2,479	2,479	2,478	2,478
On-Peak Expected Capacity (Nuclear)	2,419	2,419	2,419	2,419
On-Peak Expected Capacity (Wind)	540	540	540	540
On-Peak Expected Capacity (Solar)	5	5	5	5
Sales	3,606	3,606	3,628	3,628
Purchases	4,832	4,832	4,832	4,832
Total Capacity	61,578	61,578	61,902	61,902

c. Coincident forecast 50/50 peak seasonal demands

The SPP 2014 LTRA coincident forecasted seasonal values are listed below, along with simulation results from GridView. Differences in demand values and net energy between this assessment and the 2014 SPP LTRA report are discussed in section 3a.

50/50 peak seasonal demands

Peak Load	2016		2018	
	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
LTRA	50,993	36,702	52,267	38,549
Simulation	49,300	36,145	50,542	35,908
Difference	1,693	557	1,725	2641

d. Net Energy for Load

Net Energy for Load

Net Energy	2016	2018
	(GWh)	(GWh)
LTRA	249,560	253,770
Simulation	253,176	258,648
Difference	-3,616	-4,878

e. MRA metrics results

LOLH is the Hourly Loss-Of-Load expectation. This metric provides the hours of resource reliability shortfall per year, which is the time in hours that the demand exceeds the capacity throughout the year. The LOLH is measured in hours in GridView, which is the number of hours in a year that a loss of load event occurred. This value is a summation of hourly events for a 24-hour period, which is then averaged over the number of yearly trials.

Daily LOLE is the expected daily occurrences of the loss of load throughout the year. Per the SPP Criteria, generation reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of one day in 10 years (0.1 day/year).

EUE is the expected amount of megawatt-hours of load that will not be served in a given year. This is the summation of the expected amount of unserved energy during the time that the demand exceeds the capacity throughout the study year. GridView provides Expected Energy Not Served (EENS), which equates to EUE.

Normalized EUE provides a sense of how much energy, relative to the area's size, could be expected to be unserved. The calculation for normalized EUE is as follows: Normalized EUE = [EUE/(Net Energy for Load simulated)] x 1,000,000

f. Study Results

The values in the table below reflect the results of the GridView LOLH/LOLE simulations for both study years (2016, 2018), as well as the two reserve margins types for the NERC report[5]. Based upon the given LTRA values, no loss of load was shown in the SPP footprint for the 2016 and 2018 summer.

MRA metrics results

SPP Region	2016	2018
Forecast Planning Reserve Margin (%)	23.6%	21.5%
Forecast Operable Reserve Margin (%)	19.6%	17.3%
LOLE (days/year)	0	0
LOLH (hours/year)	0	0
EUE (MWh/year)	0	0
EUE (Normalized MWh/year)	0	0

[5] Traditionally SPP calculates capacity margin (CM), instead of reserve margin. The conversion of the two reserve margins above show a 19.1%/17.7% CM for 2016/2018 forecast planning reserve margin and 16.4%/14.7% for 2016/2018 forecast operable reserve margin.

2. Software model description

a. Computational approach

GridView 9.1.12 was used to perform the analysis. GridView is a software application developed by ABB Inc. to simulate the economic dispatch of an electric power system, while monitoring key transmission elements for each hour. GridView can be used to study the operational and planning issues facing regulated utilities, as well as competitive electric markets. The key advantage of using the GridView application is having the ability to model a detailed transmission system in the study region, not just a transportation model. The transmission model allows for realistic power delivery based on actual modeled limits on transmission lines imported from powerflow models. Some other features available in this program include contingency constraints, nomograms, and emergency imports. A sequential Monte Carlo simulation was used to perform the analysis of the SPP reliability assessment.

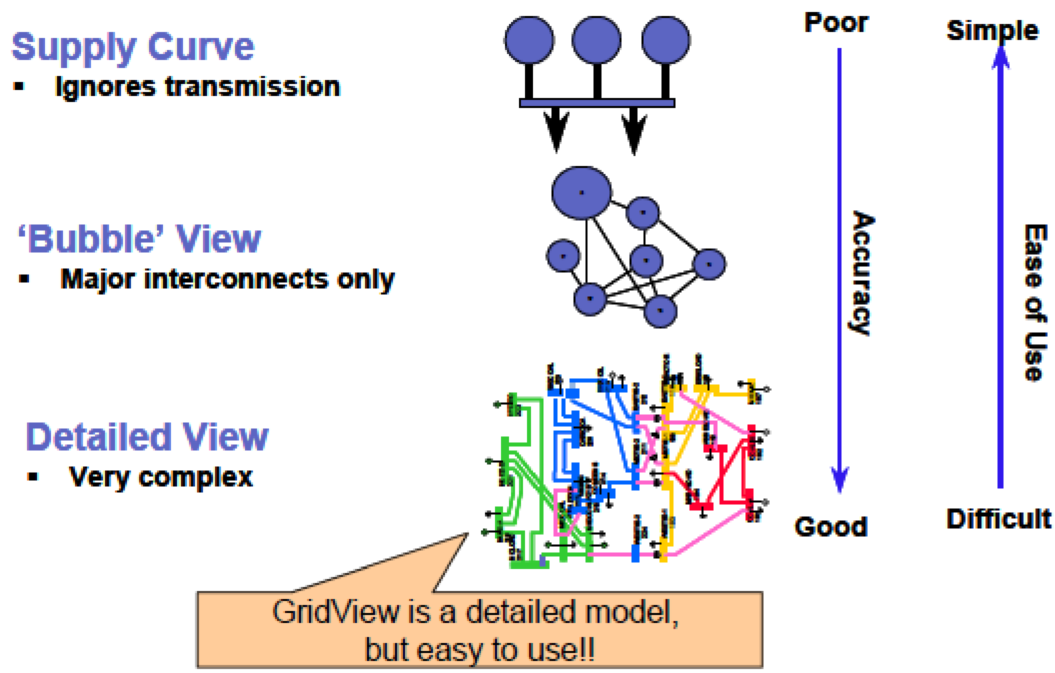


Figure 1-2 GridView Uses Very Detailed Transmission System Model

b. Algorithm usage

Monte Carlo simulation is a method for iteratively evaluating a deterministic model using sets of random numbers as inputs. The goal is to determine how random variation or uncertainty affects the reliability of the system that is being modeled. Monte Carlo simulation is categorized as a sampling method, because the inputs are randomly generated from probability distributions to simulate the process of sampling from an actual population. Within GridView, Monte Carlo simulation allows detailed modeling of the pre-contingency conditions and outages of generation and/or transmission equipment and/or changes in demand, fuel prices, and/or wind generation. GridView can also model the correlation between area load demands and fuel prices. It uses probability distributions for equipment outages during a sequential mode of simulations hour by hour, and typically for a year. The selection of testing conditions is by random sampling. In order to obtain accurate risk indices, many simulations will have to be performed (2,400 simulations/year for this assessment). In general, the simulations provide the loss of load reliability indices. For reliability assessment, a linear model is applied to the generation dispatch calculation for every hour in each trial in order to compute the amount of load shed in order to eliminate transmission overload problems. The engineer performing the analysis will choose a distribution for the inputs that most closely matches data the MRA already has, or best represents the MRA's current state of knowledge.

c. Tiered simulation

The 2014 Probabilistic Assessment was modeled in a tiered approach that became more and more constraining as the study advanced. This was akin to multiple scenarios for SPP, and allowed the footprint to be analyzed under more and more constricting parameters. The first simulation type was a transmission model both internal and external to the SPP PC footprint. No limits were attached to the transmission model, and any amount of power necessary could flow to solve the case. Next, important flowgates and interfaces within SPP and between SPP and its first-tier areas were added to the model. With these, flow was monitored on these lines and kept within the appropriate transmission line ratings. The final tier was to monitor and enforce ratings on all 230kV and above transmission lines within SPP and its first-tier areas. The 230kV distinction was chosen based on simulation time. Without any lines being monitored, simulations ran 17-18 hours. With 230kV and above being monitored, simulation time increased to 65 hours. At 100kV and above, simulations were estimated at taking 40+ days per case, which was unfeasible for this study.

d. External area modeling

GridView allows external areas to be modeled in the same fashion as internal areas. The key difference between the two is that external load and generation is ignored. External transmission; however, is considered for calculating flow on lines.

3. Demand Modeling

a. Explanation of differences between reported data and LTRA

There are two reasons the reported 2014 LTRA demand and simulation differences. For the simulation, net internal demand, which excluded the projected available demand response, was used with interruptible load being explicitly modeled, as described in section 4a. Secondly, GridView only allows for the adjustment of the annual peak demand, which occurs during the summer in SPP models. When the annual peak is adjusted, the winter peak and every other hour will be adjusted by a proportional amount, based on the hourly load profile. This functionality prevents the winter peak value from aligning with what is provided in the LTRA.

The difference between the net energy and the LTRA is also attributable to the proportional adjustment of the hourly load profile.

b. Explanation of chronological load model and loads accounted for out of region

Each MRA modeled has its own expected 8,760 hourly load profile. The hourly load curves are a normalized average of years 2007-2011. These years provided a typical range of weather and load patterns, along with being the most recent years available. SPP used 2016 and 2018 hourly non-coincident peak load forecast data to create the hourly load profiles for each entity in this assessment. The hourly load profiles were then adjusted using a coincident peak for each entity. The coincident peak was calculated using the peak demand from the averaged 2007-2011 average load shape for the entire SPP region. Each MRA's non-coincident peak from their averaged 2007-2011 average load shape was divided into their coincident peak demand. This ratio was then multiplied by the LTRA peak to gain a coincident peak for each MRA.

$$Eq.1\colon \frac{Coincidence_{hist.avg.}}{Non\ Coincidence_{hist.avg.}} = ratio_{hist.avg.}$$

$$Eq.2\colon ratio_{hist.avg.} * \ NC_{LTRA} = C_{LTRA}$$

No out-of-region load was modeled in this assessment.

c. Explanation of how load forecast uncertainty was modeled

i. Method

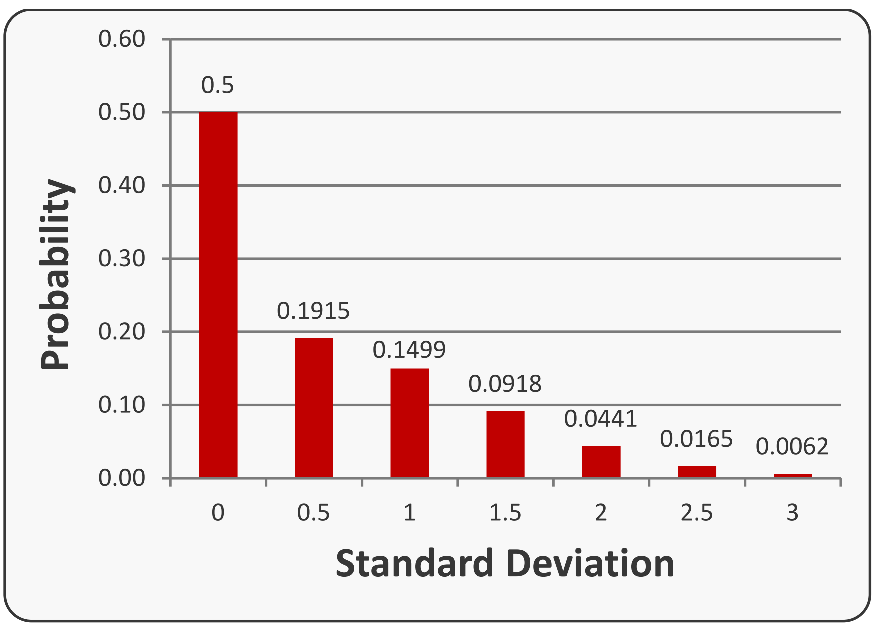
GridView allows for two options in dealing with load uncertainty: 1) User defined uncertainty pattern, and 2) probability distribution. For this study, a user-defined uncertainty pattern and a probability distribution were both used to add uncertainty to the load values. A different load uncertainty was created for each MRA.

ii. Uncertainty Components

A load model was used to define the peak-load multipliers used to modify forecasted loads. The daily peak was selected and regressed against historical peak temperatures from 2006-2011. Crystal Ball Pro was used to analyze the probability distributions of temperatures observed at key weather stations throughout the SPP footprint. The load model increased load as the winter temperatures decreased and as the shoulder and summer temperatures increased. A forecast was then created for both study years. Based on the forecasts, multipliers were calculated and were populated in a user defined uncertainty pattern. The user-defined uncertainty pattern allows users to provide seven monthly load patterns. Each area has a different value for each month times seven probabilities (a total of 84 values). GridView randomly selects the load pattern at the beginning of the simulation hour, and applies it for that trial. The same uncertainty model used in the 2012 Probabilistic Assessment was used in the 2014 Probabilistic Assessment.

iii. How the probability is incorporated

The randomly selected load multipliers were determined by sampling from a uniform distribution, and selecting one of seven possible multipliers. These multipliers have dramatically decreasing likelihoods (e.g., Set 1 is 50% likely, Set 2 is 19% likely, Set 7 is 0.6% likely). Multiplier Set 7 contain the highest multipliers, and are the least likely to occur. As such, this set should be considered SPP's extreme peak. No multipliers decrease the load values in this study. Multiplier Set 1 is the base case multiplier, and effectively multiplies all loads by 1. Sets 2–7 are intended to proportionally increase loads up to SPP expected extreme peaks.



iv. How the MRA considered the uncertainty of different entities within the MRA

The load-uncertainty probability took into consideration stochastic temperature within the different areas, in addition to recognizing the structural affects that holidays, weekends, quarters, and previous hour's load have on load expectations. Other sources of uncertainty reasonably independent of temperature are modeled were considered to be sufficiently small in magnitude and not necessary at this time to model independently. A random error term was created to incorporate variability that could occur from uncertainty types such as economic industrial/commercial health and dew point.

d. Explanation of how behind-the-meter generation was modeled

Behind-the-meter generation is generally netted and modeled with customer load. If the behind-the-meter generation is not netted, then it was modeled as regular generation. If the behind the meter generation was not tied to its own bus, then the capacity was divided between its associable generation units within the power flow model.

4. Controllable Capacity Demand Response Modeling

a. Explanation of how controllable capacity demand is modeled

SPP has controllable-capacity demand in the form of Interruptible (Curtailable) demand. In areas that reported controllable-capacity demand, equivalent thermal units were added to the model with high fuel costs assumed, so those units would be dispatched last to reflect demand-response operating scenarios.

5. Capacity Modeling

a. Difference between the MRA and LTRA capacities

The key difference between MRA and LTRA resource totals is the equivalent demand-response generation included for the MRA models, used for the Probabilistic Assessment. Sales and purchases were also different from what was reported in the LTRA. For the Probabilistic Assessment, the purchases and sales from the SPP OASIS and service agreements identified as being firm were used, to maximize potential capacity available to MRA, as well as properly reflect capacity exports.

b. Determination of whether "Future, Planned" generation is "firm and deliverable

All generation, future or otherwise, must have firm transmission service in the form of a service agreement or an OASIS transaction to be modeled.

c. Explanation of how jointly owned units are modeled

Jointly owned units were modeled as thermal generators, with the percentage of ownership calculated as capacity for that specific unit. GridView allows the unit's capacity to be split up between multiple areas, using the Reserve Capacity Distribution feature. If a MRA owned 50% of a generator in a separate SPP MRA, the reserve capacity distribution would show 50% going to the other MRA. If the generator was owned by an entity outside of SPP, the capacity of the unit was dropped by the percentage owned outside the area.

d. Capacity sales and purchases

If the sale was generator-specific, the capacity of the sale was taken as a percentage of the generator's max capacity, and then assigned to the purchase area. If the sale was generic from one area to another, the sale's capacity was taken as a percentage of the entire area's maximum capacity, and then represented as an hourly resource of that amount. The resource would be located on the selling area's swing bus, but owned by the purchasing area. An hourly resource with an equal negative capacity would be placed on the selling area's swing bus. The negative capacity amount was a summation of the total exports for a specific area. This methodology allows for area capacity correction in accordance with sales and purchases modeled in each study area.

If the sale or purchase was between a SPP MRA and an outside entity, a generator was placed on the outside entity swing bus for the amount of the transaction. The generator area was changed to the SPP MRA, so that it would be included in the study. If the transaction was a sale to the outside entity, the capacity would be negative. If a purchase, the capacity would be positive

e. DC Ties

An average of the 2007-2011 actual hourly value was used to generate the hourly shape, for DC ties. An equivalent hourly resource was created to reflect this hourly shape.

f. Intermittent and energy-limited variable resources

Wind generation was modeled as an hourly resource using 2007-2011 data from a combination of actual energy generation and estimated energy generation, based on National Renewable Energy Laboratory (NREL) wind-shape data, as required. The hourly wind shapes consist of 8,784 hourly values for year 2016 and 8,760 values for year 2018. If a wind resource was not in service for any part of a year, NREL data was used to supplement where needed. The two data sets were first normalized before being combined and averaged. The resultant hourly wind shapes were imported into GridView to provide an accurate profile of the wind generation output for each hour in the year.

g. Traditional dispatchable capacity

i. Ratings

The maximum capacity ratings were based on 2014 LTRA data, as developed by the SPP member's capability testing. The capability testing procedure and requirements are described in SPP Criteria section 12.1.1[6]

ii. Forced outage modeling

Forced outage modeling within GridView consists of using the Equivalent Forced Outage Rate – demand (EFORd) values provided from Ventyx[7]. - Values for forced outage rates, forced outage durations, and scheduled maintenance

[6] http://www.spp.org/publications/SPP%20Criteria%20and%20Appendices%20Jan.%202012.pdf

[7] http://www.ventyx.com/

requirements are taken from Energy Velocity, using data from the NERC Generating Availability Data Systems (GADS) and supplemented by Ventyx Advisors staff based on generator age.

iii. **Planned outage modeling**

Planned outages for thermal units were modeled by using the scheduled maintenance function in GridView to take units offline for a specified period of time based on start time, end time, and duration. Once the outage duration elapsed, the unit was placed back online in the model. The maintenance start date and outage duration were sourced from Control Room Operations Window (CROW) software SPP members use to plan maintenance outages. If generators did not have a designated outage planned, previous planned outage times were modeled.

6. Transmission

a. Transmission additions and retirements

System Topology was drawn from the 2013 ITPNT series summer models for the 2016 and 2018 study years. Transmission additions and retirements were captured in the ITPNT models built with SPP member input and modeling. Transmission additions were modeled and retirements were removed from the GridView models. Several retirements were announced after the LTRA posting. These were retired in the GridView case.

b. MRA's transmission modeling approach

GridView allows importing of transmission data from a PSS/E power flow model. For each study year (2016, 2018), separate ITPNT models were imported to represent the latest representation of the SPP transmission grid.

Internal and crossing interfaces for years 2016 and 2018 were implemented using the SPP Operation's OASIS flowgate list. Interfaces are key groups of transmission lines that should be all observed as one group, such as key transmission lines between one MRA to another.

Internal and crossing flowgates for years 2016 and 2018 were implemented using the Outage Transfer Distribution Factor (OTDF) and Power Transfer Distribution Factor (PTDF) flowgates outlined in the SPP OPS OASIS flowgate list.

7. Assistance from External Resources

a. Quantifying non-firm assistance from resources outside of the MRA's footprint

For this Probabilistic Assessment, it was assumed that SPP does not rely on non-firm assistance from resources outside of the SPP assessment area footprint, consistent with the LTRA report's values.

8. Definition of Loss-of-Load Event

a. MRA's definition of loss-of-load event

A loss-of-load event, as defined in this Probabilistic Assessment, is any load that is not served, or load that is greater than available generation.

9. Scenario Modeling

a. Scenario Simulation

Base-case simulation for SPP includes enforcing operating reserve. As this was the scenario requested by NERC, our simulation would be not enforcing reserve. With the operating reserve being enforced, no loss of load was experienced. Without enforcing load and having extra capacity, no loss of load would be experienced either.

Demand and Capacity Data for 2014 Probabilistic Assessment

	2016
ENERGY	**Annual**
Net Energy for Load - Annual (GWh)	249,560

	2016	
DEMAND	**Winter**	**Summer**
Total Internal Demand		
Expected Demand (50/50)	36,702	50,993
Low Forecast Cummulative Probability	10%	10%
Low Forecast Demand		
High Forecast Cummulative Probability	90%	90%
High Forecast Demand		
Demand-Side Management - Program Total	**1,095**	**1,522**
Direct Control Load Management (DCLM)	130	215
Interruptible Load	956	1,298
Critical Peak-Pricing (CPP) with Control	9	9
Load as a Capacity Resource	0	0
Demand-Side Management - Available	**1,060**	**1,306**
Direct Control Load Management (DCLM)	70	203
Interruptible Load	981	1,094
Critical Peak-Pricing (CPP) with Control	9	9
Load as a Capacity Resource	0	0
Net Internal Demand	**35,642**	**49,687**

	2016	
CAPACITY	**Winter**	**Summer**
Capacity Installed		
Coal	24431	24431
Petroleum	1632	1632
Gas	29547	29547
Nuclear	2419	2419
Other	54	54
Hydro	2479	2479
Pumped Storage	446	446
Geothermal	0	0
Biomass	25	25
Wind	540	540
Solar	5	5

Capacity Expected On-Peak (Summer/Winter Certain/Planned)	**64,096**	**63,248**
Coal	26,887	25,461
Petroleum	1,267	1,267
Gas	30,023	30,549
Nuclear	2,407	2,407

Other	16	16
Hydro	2,641	2,641
Pumped Storage	480	480
Geothermal	0	0
Biomass	24	27
Wind	346	394
Solar	5	5
Capacity Adjustments On-Peak		
Scheduled Outages	235	235
Transmission Limitations	18	4
Other	0	0
Weighted Average Forced Outage Rate On-Peak		
Coal	7.0%	7.0%
Petroleum	4.8%	4.8%
Gas	5.1%	5.1%
Nuclear	2.8%	2.8%
Other	0.0%	0.0%
Hydro	0.0%	0.0%
Pumped Storage	0.0%	0.0%
Geothermal	0.0%	0.0%
Biomass	4.2%	4.2%
Wind	0.0%	0.0%
Solar	0.0%	0.0%
Operable Capacity Resources	**60534**	**59767**

	2016	
CAPACITY TRANSFERS	**Winter**	**Summer**
Imports		
Firm	4,832	4,832
Expected	0	50
Exports		
Firm	3,606	3,606
Expected	0	0

	2016	
CAPACITY OBLIGATIONS & OPERATING PROCEDURES	**Winter**	**Summer**
Other Obligations from Resources	**2550**	**2550**
Non-Spinning Reserves	1700	1700
Spinning Reserves	850	850
Other Obligations	0	0
Operating Procedures (Before Loss-of-Load)	**2243**	**2243**
Additional Demand Response	937	937
Non-Spinning Reserves (Forgone)	0	0
Spinning Reserves (Forgone)	0	0
Other Obligations (Forgone)	0	0

Interruptible Load	1306	1306
Voltage Reductions	0	0
Public Appeals	0	0
Other	0	0

	2016
PROBABILISTIC STATISTICS	**Annual**
Expected Unsupplied Energy (EUE) (MWh)	0.000000
Loss of Load Hours (LOLH) (hours/year)	0.000000

	2016
SUMMARY TABLE	**Annual**
Net Energy for Load (GWh)	249560
Total Internal Demand (MW)	50993
90th Percentile (% above 50/50 forecast)	#NUM!
Net Internal Demand (MW)	49687
Forecast Capacity Resources (MW)	63063
Forecast Operable Capacity Resources (MW)	60993
Expected Unsupplied Energy (EUE) (MWh)	0.000
Expected Unsupplied Energy (EUE) (ppm)	0
Loss of Load Hours (LOLH) (hours/year)	0.000
Forecast Planning Reserve Margin (%)	26.9%
Forecast Operable Reserve Margin (%)	22.8%

Manual Data Entry Optional (Prepoluated from LTRA Anticipated Capacity)	
Manual Data Entry Required	
Manual Data Entry Completed	0
Calculated Statistic	

2018
Annual
253,770

2018	
Winter	Summer

38,549	52,267
10%	10%
90%	90%
1,098	**1,614**
133	222
956	1,383
9	9
0	0
1,051	**1,323**
73	220
969	1,094
9	9
0	0
37,498	**50,944**

2018	
Winter	Summer
24680	24680
1632	1632
29623	29623
2419	2419
54	54
2478	2478
446	446
0	0
25	25
540	540
5	5

63,118	**63,388**
25,415	25,466
1,266	1,266
30,406	30,560
2,412	2,479

16	16
2,641	2,641
480	480
0	0
27	27
449	448
5	5
0	0
18	4
0	0

7.0%	7.0%
4.8%	4.8%
5.0%	5.0%
2.8%	2.8%
0.0%	0.0%
0.0%	0.0%
0.0%	0.0%
0.0%	0.0%
4.2%	4.2%
0.0%	0.0%
0.0%	0.0%

59678	**59936**

2018	
Winter	**Summer**

4,832	4,832
0	0

3,628	3,606
0	0

2018	
Winter	**Summer**
2550	**2550**
1700	1700
850	850
0	0
2120	**2120**
797	797
0	0
0	0
0	0

1323	1323
0	0
0	0
0	0

2018
Annual
0.000000
0.000000

2018
Annual
253770
52267
#NUM!
50944
63388
61162
0.000
0
0.000
24.4%
20.1%

ITP Load and Generation Review

Kelsey Allen

10/23/2014

Southwest Power Pool

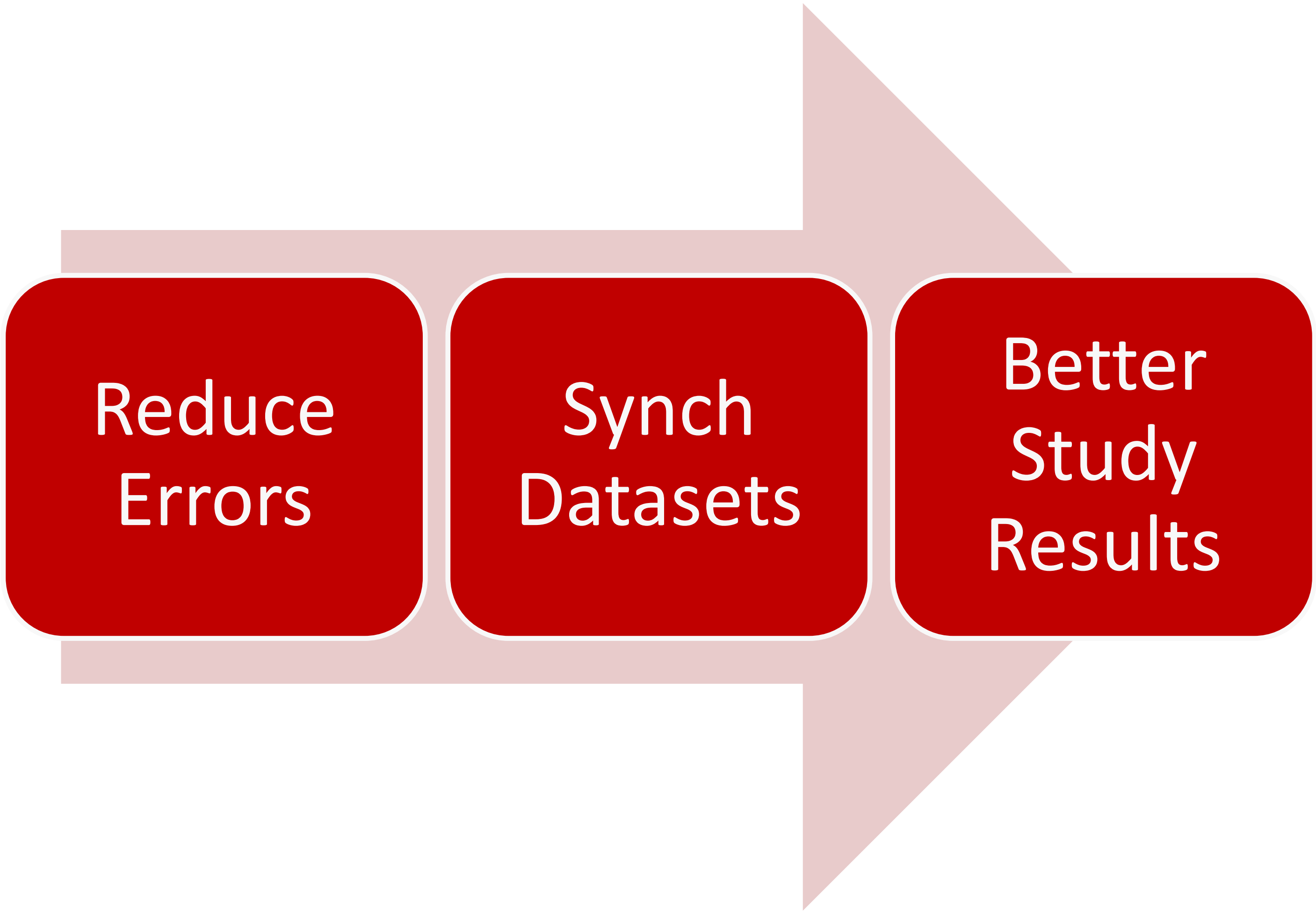
Current Load and Gen Review

- Generation Review
  - Review existing generator data
  - Defines new generators with economic data
- Load Review
  - Review of peak load from the approved MDWG powerflow models
  - Requests each company's peak load with losses and annual energy

Issues/Improvement Plan

- Issues
  - Long process in each ITP10/20 study
  - Potential inconsistencies in SPP models
- Improvement plan
  - Roll the Gen and Load review into the established MDWG process
    - MDWG PROMOD Data Submittal Form
    - Automated data checks
  - Provide short window for review in ITP cycle

Purpose



Next Steps

- Finalize the submittal form
- Take to the ESWG, TWG, and MDWG in November
- Send out PROMOD workbook with first available MDWG Pass

2017 ITP10 Scope

SPP Staff

October 23rd, 2014

Southwest Power Pool

Overview of 2017 ITP10

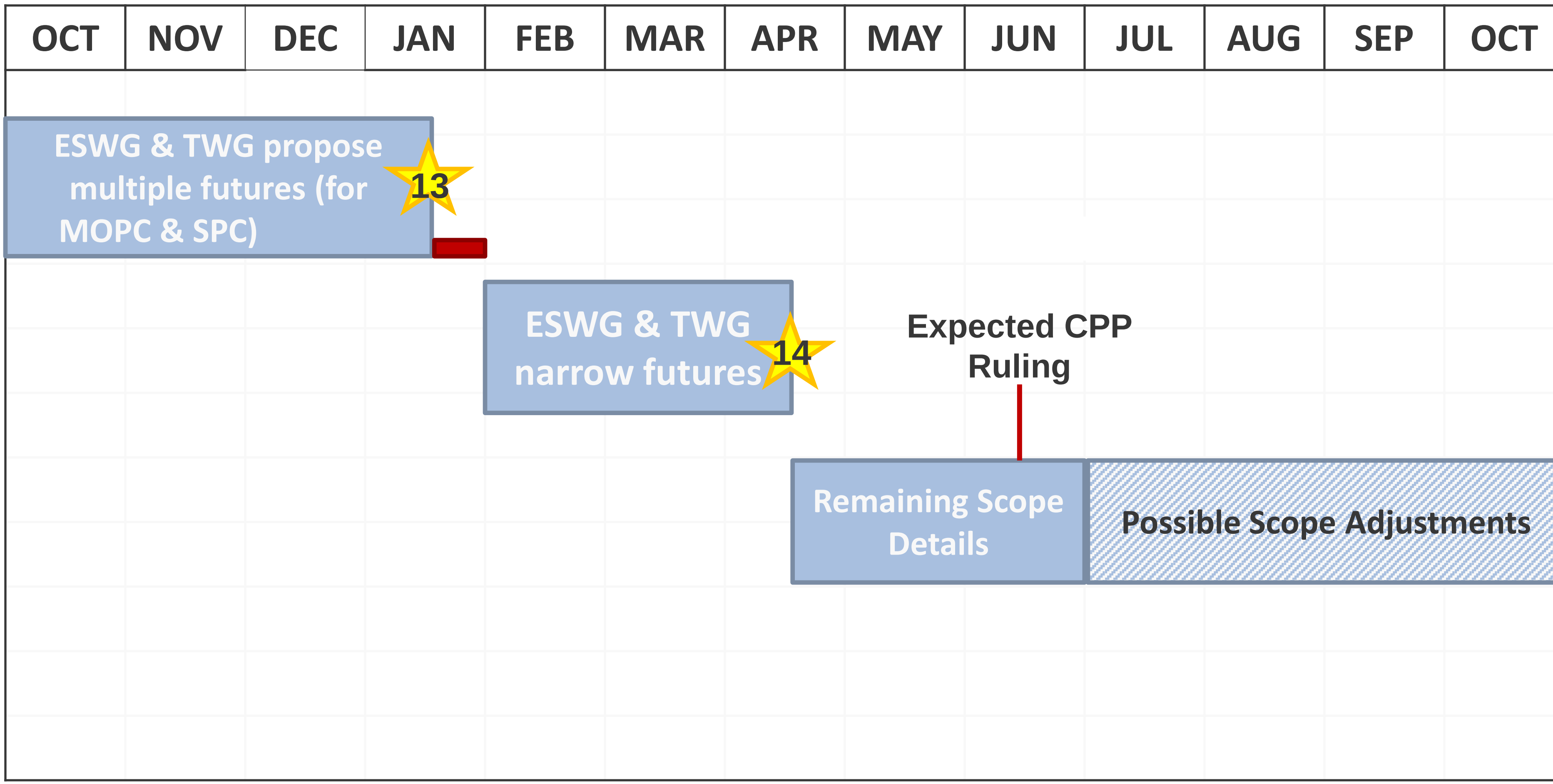
- Integrated Transmission Planning Year 10 Assessment
- Study Year 2025
- MOPC approved ESWG recommendation for next planning cycle*

*Subject to EPA schedule

Scope Process Summary

- ESWG, TWG will initially propose an expanded set of futures
  - Including high-level assumptions for those futures
  - List of futures taken to MOPC/SPC in January 2015
  - MOPC/SPC will provide feedback on the options presented
- ESWG, TWG, and SPC narrow down the proposed futures
  - January - April
  - Take a subset of futures back to MOPC in April for approval
- Remaining Scope Details finalized in July-October 2015

2017 ITP10 Scope Timeline



Working Group/Task Force Approval
Member Review/Feedback Period
Milestone Period

Next Steps

- ITP20 Waiver
  - Forgo the ITP20 for the next ITP Planning Cycle
- 24-month ITP10 Study
  - Begin scoping ITP10 in January 2015
  - Begin ITP10 model development in July-October 2015
    - Subject to EPA adhering to the CPP schedule

Futures and Assumptions

- Number of Futures
- EPA Regulations
- Weather Impact Forecast
- Technological Innovation
- Commodity Prices
- Economy Growth
- Other

SPP Scenario Development
ESWG Meeting

May 2013

Bridge Strategy Group LLC

SPP Southwest Power Pool

SPP Scenario Development

Introduction to Scenarios

Identifying Critical Business Drivers & Developing Potential Scenarios

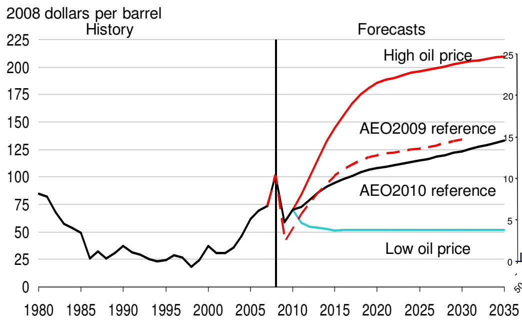
Articulating the SPP Planning Scenarios

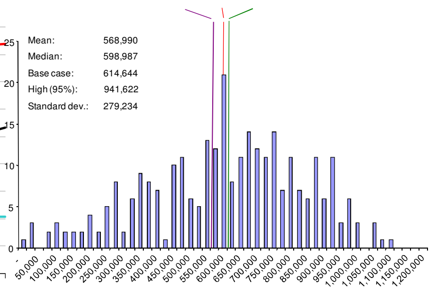
Scenarios play a key role in developing robust and credible long term strategic plans

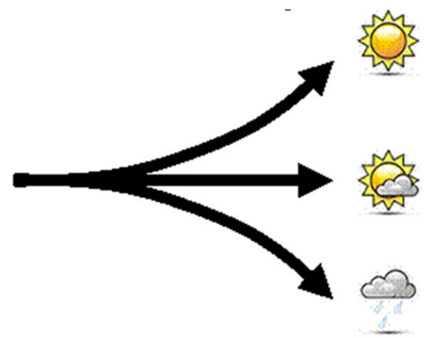
ROLE OF SCENARIOS

- Scenarios are designed to help companies **confront conventional wisdom, challenge assumptions,** and develop robust strategies
- Scenarios **are not projections, predictions, or consensus building exercises**; rather, they are coherent and credible **alternative stories** that describe a unique and compelling potential future states
- The development process **engages the organization** and helps address difficult issues that need to be **explored collaboratively** even though opinions may be deeply divided on potential outcomes
- When considering scenarios for planning purposes, ***the process of collaborative exploration is equally as valuable as the resulting scenarios themselves***

The issues facing the industry in general, and SPP specifically, call for dealing with uncertainty in ways that traditional forecasting techniques simply do not







TRADITIONAL FORECASTING & SIMULATION

- Traditional forecasting and simulation techniques are valuable but *incomplete*
  - Suffer from “The Rear View Mirror Trap” by relying heavily on the past to inform the future
  - Predict the future deterministically (traditional forecasting) or to a certain degree of probability (simulation)
  - Deal with risk quantitatively through sensitivity analysis (forecasting) or Monte Carlo analysis (simulation) but do not deal effectively with uncertainty (unquantifiable randomness)

SCENARIO ANALYSIS

- Scenario analysis explores what is *possible* in the future
  - Inherently forward looking, informed but not constrained by the past
  - Considers multiple correlated variable outcomes in a plausible and compelling fashion
  - Contemplates ahistorical events that may represent significant change or transformation from current conditions – “black swans”

Conventional wisdom by definition fails, oftentimes catastrophically; developing scenarios can help thinking about 'what if' in a structured way

THE TECHNOLOGY TRAP: A.K.A. "THAT WILL NEVER HAPPEN"

- "Fooling around with alternating current is just a waste of time. Nobody will use it, ever."
  Thomas Edison, American inventor – 1889
- "Heavier-than-air flying machines are impossible"
  Lord Kelvin, British mathematician and physicist, President of the British Royal Society – 1895
- "I think there is a world market for maybe five computers"
  Thomas Watson, chairman of IBM – 1943
- "There is no reason anyone would want a computer in their home"
  Ken Olson, President, Chairman and founder of Digital Equipment Corp –1977

THE TREND TRAP: A.K.A. "WHY WOULD TOMORROW BE ANY DIFFERENT THAN TODAY"

- "Stocks have reached what looks like a permanently high plateau"
  Irving Fisher, Professor of Economics, Yale University – 1929
- "1930 will be a splendid employment year"
  U.S. Department of Labor – 1929
- "In China there is little hope for rapid increases in domestic savings beyond current high levels"
  Alden Clausen, President, World Bank – 1983
- "We do not expect significant spillovers from the subprime market to the rest of the economy or to the financial system"
  Ben Bernanke, Federal Reserve Chairman, – 2007

Other RTOs are beginning to adopting scenario-based approaches

ISO	Planning Specifics & Key Drivers	Scenarios Considered
MISO	• 5 year and 15 year plans • **Regulation** to address reliability issues and RPS requirements, rate increase between 7-7.6% • **Generation retirement** of 13GW coal generation at risk • **Market efficiency**, provide cost mechanism to realize economic benefit over time, mitigate risk • **Load growth** based between 44K and 70K (MW)	• Business as Usual with Mid-Low Demand and Energy Growth Rates:. • Business as Usual with Historic Demand and Energy Growth Rates: • Carbon Constraint Future • Combined Energy Policy Future: RPS & carbon cap, smart grid & EV
ERCOT	• 5 year and 20 year plans • **Load growth** +3.5% annually through 2016 • **Operational Results** • **Generation Interconnections**, to plan for and process the integration of new generation sources • **Transmission and System Studies**, analysis of grid congestion and to ensure reliability standards	• Business as Usual • Business as Usual with PTC/RPS, national carbon tax, and higher natural gas prices • Extreme Drought • High Emerging Technology – DR, EE, DG, and energy storage
pjm	• 5 year and 15 year plans • **Load growth** of 1.7% 2010-2025 • Changing of **generation fuel mix** • **Generation retirement** totaling 25 facilities covering 9 transmission organization zones • **Regulation** requiring RPS and strict reliability standards	• Has used simulation techniques in the past for the Regional Transmission Expansion Plan (RTEP) to generate up to 6,000 individual states of the world • Beginning to integrate limited scenarios primarily around load growth for the most recent RTEP

Scenarios benefit strategic planning by considering the future that is neither completely predictable nor completely random

BENEFITS OF SCENARIOS

- **Present a backdrop for the design and selection of strategies**. Since it is difficult to construct a single strategy that can perform best in each scenario, special selection criteria, such as “bet on the most probable scenario” or “preserve flexibility” are needed
- Help **make managers aware of the magnitude and complexity of uncertainties** by challenging them with fundamentally different future states across multiple drivers
- Provide a tool to help an organization **act upon or anticipate future developments**. As such, scenarios can serve as early warning systems and prevent reactionary behavior when conditions change
- Offer the possibility to **combine quantitative data with qualitative input**, enabling scenario planners to incorporate results from other forecasting techniques and allow for soft and fuzzy variables.

SPP Scenario Development

Introduction to Scenarios

Identifying Critical Business Drivers & Developing Potential Scenarios

Articulating the SPP Planning Scenarios

Bridge interviewed several individuals to discuss how to approach the development and use of scenarios in long-term strategic planning

INDIVIDUAL INTERVIEWEES

- **Directors:**
  - Larry Altenbaumer
  - Phyllis Bernard
  - Julian Brix
  - Jim Eckelberger
  - Josh Martin
  - Harry Skilton
- **Members:**
  - Ricky Bittle – AK Electric Coop
  - Bill Dowling – Midwest Energy
  - Cindy Holman – OMPA
  - David Hudson – Xcel Energy
  - Mike Palmer – Empire District
  - Mel Perkins – OG&E
  - Stuart Solomon – PSC OK
  - Norman Williams – Sunflower Electric
  - Mike Wise – Golden Spread
- **Officers:**
  - Nick Brown
  - Michael Desselle
  - Stacey Duckett
  - Tom Dunn
  - Carl Monroe
  - Lenny Nickell
  - Bruce Rew
  - Barbara Sugg
  - Paul Suskie
- **Regional Entity Trustee**
  - John Meyer

When we asked those individuals about key issues and uncertainty drivers facing the industry and SPP directly, we heard three types of things

LOAD GROWTH RELATED

- Consumer demand for energy
- Industrial growth in SPP footprint: e.g., new chemical and fertilizer plants, data centers, irrigation, etc.
- Energy efficiency and demand response
- Weather (drought)

OTHER

- Evolution of FERC regulation
- Evolution of adjacent markets e.g. ERCOT and outcomes from other RTOs
- IT and physical security – future needs and linkage with utility customers
- Aging workforce-Implication for skills, costs, growth

GENERATION RELATED

- Coal concerns
  - Impact of EPA regulations
- Trajectory of natural gas prices
- Role of wind in the US and regional generation mix – technical and political targets
  - What do we think is 'right'? 'technically optimal?"
- Mix of central vs. distributed generation
- Biomass and ethanol uncertainty
- Solar - Installed cost of PV, batteries
- Regulatory push for fuel diversity
- Water concerns
  - Availability for generation, fracking, and irrigation

In the first workshop, participants considered a broad range of uncertainties and reached consensus on a set of critical drivers through group discussion and a breakout session

STARTING POINT BASED ON INITIAL INTERVIEWS (TEED UP FOR DEBATE AND CONSIDERATION IN BREAKOUT GROUPS)

1. Natural gas price and volatility
2. Innovation in supply technologies
3. Role of distributed generation
4. Environmental legislation
5. FERC and other federal regulation
6. State/ regional regulation
7. Availability of capital
8. Electric load growth
9. Consumer preferences
10. Perceived value to members

CRITICAL DRIVERS (BREAKOUT CONSENSUS)

- Commodity (natural gas) prices
- Environmental / general regulation & legislation
- Consumer perceptions of reliability & cost
- Economic / electric demand growth
- Innovation – Renewables, DG, SG, etc.

OTHER CRITICAL DRIVERS (GROUP CONSENSUS)

- Water supply and grid security

In the second breakout session in September, the groups discussed what range of values each of the drivers could take in the future

DRIVER CATEGORIES	DRIVER	VARIANTS
Commodity Markets	Natural Gas Prices	$2-3 / Mcf
		$4-6 / Mcf
		$8-10 / Mcf
	Water Supply	Stable
		Shortage due to restrictions
		Flooding
Regulation	Environmental / General Regulation & Legislation	Current
		Rollback
		No PTC
		Carbon Tax
Growth	Economy	0% - 5% (real GDP)
	Demand	0% - 6+% (electric demand)
Technology	Renewables & Storage (Transmission Level)	<5%
		5-10%
		10-30%
	Renewables &Storage (Sub Transmission Level)	<1%
		3%
Consumer	Reliability	Perceived as stable
		Cyber or physical risk
		Forced plant closure
	Affordability	Status quo
		Contested

SPP Scenario Development

Introduction to Scenarios and Project Overview

Identifying Critical Business Drivers & Developing Potential Scenarios

Articulating the SPP Planning Scenarios

In our January workshop, in order to jump-start the scenario development process, Bridge formulated examples of scenarios to demonstrate potential future outcomes, similar to how some SPP members do scenario development

Dominant Theme	Driver Description	Potential Scenarios
Government Intervention	Governments intrude in the industry in varying degrees with varying goals	"Bye-Bye Baseload"
		"Boom to Bust" (Gas Supply Bust)
		"European Vacation"
Technological Innovation	Significant change in technological innovation rate ranging from narrow to broad in scope	"BTU Renaissance"
		"New Transmission Model"
		"Industrial Revolution 2.0"
Externalities	Cyber terrorism	"Dark Days Ahead" (Infrastructure Attacked)
	Economic stagnation	"Lost Decade"
	Climate change resurgence	"Polar Meltdown"

Construction of the scenarios

SCENARIO DEVELOPMENT CONSIDERATIONS

- The time frame of the scenarios is 10 years
- After considerable discussion, it was decided to articulate an Expected Case along with alternative scenarios
- Consensus was largely attained on the Expected Case
- The group generally used an “inductive approach” to scenario development where an initiating set of “forcing events” shaped the outcomes of all of the critical drivers
- Multiple scenarios (8-10) were considered and narrowed down to the set of four through a process of elimination of overlaps and “outliers”

Based on the drivers selected by the group, the first breakout session of the January Workshop captured the thinking of each group on potential scenarios

Group 1	Group 2	Group 3
"Regional Water Shortage": • Coal plants back off and regional fracking is limited ($5-$7 gas) • Once through cooling mandated • Ag and consumers take water preference • Reduction in reliability and affordability	***"Expected Case":*** • $5-$7 gas with oil much higher • 1-2% load growth • More restrictive regulation in the electric industry • Shut down older coal & shift to gas on the margin • No new coal or nuclear	***"Cyber Terrorism":*** • Significant cost to harden the grid • All commodities more expensive • Lower load growth across the board • Repatriation of "strategic industries"
"Cyber Attack": • Attack on infrastructure drives significant federal intervention in electric market • Diversity of supply and transport – big investment in distributed generation • Gas prices unaffected - $4-$6 • Economy benefits from huge investment		***"Economic Chaos":*** • Significant bust on US/global financial markets leading to devaluation / inflation • Significantly higher prices • Much lower growth • Regulatory rollback (government defunded)
"Stability Before Change": • Low gas prices in the near term (<$4) followed by a price event rising to >$7 • Affordability a big issue • Growth slows to 1%		***"Fracking Goes Away":*** • Environmental "event" causes backlash against fracking gas goes to $8+ • Coal, Nuke, Solar replace gas gen • Prices rise and load declines
		"Middle East Conflict": • Global oil prices skyrocket … huge growth in domestic fracking business • Very high load growth (locally) • Potential disconnect in global oil prices

There was overlap in the scenarios developed in the breakout sessions allowing consolidation to 6 potential candidates … the group was given three votes on the most relevant for SPP resulting in four scenarios to be explored further

SCENARIOS FROM THE BREAKOUT

1. **“Gas Supply Bust”**
   - **“Stability Before Change”**
   - **“Fracking Goes Away”**
2. **“Middle East Conflict”**
3. **“Economic Collapse”**
4. **“Infrastructure Attacked”**
   - **“Cyber Attack”**
   - **“Cyber Terrorism”**
5. **“Water Shortage”**
6. **“Expected Case”**

SCENARIOS TO BE FULLY DEVELOPED

1. **“Gas Supply Bust”**
2. **“Infrastructure Attacked”**
3. **“Water Shortage”**
4. **“Expected Case”**

Each of the three breakout groups was asked to detail an expected case as well as one of the specific alternative scenarios and report back to the workshop group

There are several areas of alignment across the expected case results that came out of the breakouts, however, there are some areas that still require alignment

Driver	Consensus / Alignment	Differing Views to be Resolved
Environmental / General Regulation & Legislation	• Water use will be more constrained, eventually leading to mandated closed loop cooling • Regulations will generally become more restrictive but will be limited by cost pressure	• Fate of the PTC and renewable incentives in general
Commodity Prices	• Oil and agriculture prices will continue to have price pressure to the upside	• Natural gas prices – two groups indicated $5-$7/MMBtu real prices going forward, one $4-$6 with a cap at $6/MMBtu
Economy / Growth	• Growth overall of 1% to 2% across the region • Growth will be uneven driven by industrial and agricultural differences	• Nothing material
Technological Innovation	• Gas will replace coal on the margins as plants are retired, eventually nuclear as well • Distributed generation will make no material impact, EE/DR will continue with regulatory support	• Nothing material
Consumer Perceptions	• Consumers will have no real economic alternative to the current generation model • Consumers will continue to struggle economically and cost will be a key concern	• Nothing material

Scenario Summary – Gas Supply Bust

Scenario Summary	Natural gas supply is abundant for the first 5 years of the scenario but then is significantly curtailed as a result of regulation brought on by external influence (e.g. water table fouling, earth quakes, etc.) . The change is supported by the public as necessary and prudent.

Driver	Scenario Outcome
Environmental / General Regulation & Legislation	• Cheap and abundant gas allows environmental regulations to continue pressure on coal and nuclear plants, significant retirements result • Fracking techniques are significantly curtailed as a result of the externality
Commodity Prices	• Initially gas prices are low in the $3-$4/MMBtu range. Post anti-fracking regulations, prices exceed $8/MMBtu on a real basis • Electric wholesale prices rise dramatically with new reliance on gas generation – remaining coal and nuclear plants reap windfall profits
Economic Growth	• Economic growth slows as energy costs increase • Regions relying on agriculture/irrigation and oil/gas development are disproportionately hit as higher energy costs and regulations limit production
Technological Innovation	• Technologies that consume natural gas flourish initially in the low price environment • Renewable and solid fuel generation make a come back in the higher gas price environment
Consumer Perceptions	• Consumer support of fracking evaporates as a result of significant environmental problems • Potential for backlash as utilities are blamed for price increases by politicians and activists

Scenario Summary – Water Shortage

Scenario Summary	A drought of significant duration (5+ years) settles over the central US. The loss of ground and surface water cause significant changes in the public perception and regulatory treatment of water usage.

Driver	Scenario Outcome
Environmental / General Regulation & Legislation	• Large scale use of water is highly scrutinized • Ethanol, irrigation, power generation and other industrial water usage is significantly impacted • Closed loop water processes are all that is acceptable
Commodity Prices	• Closed loop fracking is mandatory adding $0.50/MMBtu to natural gas prices and minimally to oil fracking • Agriculture prices rise significantly as irrigation is curtailed and production falls
Economic Growth	• Decline in agricultural production significantly impacts SPP load growth • Loss of load from irrigation combined with depopulation cause demand to decline at a rate approaching 1% per year over the period
Technological Innovation	• All thermal power generation must use closed loop cooling – new and existing • Renewable and other low water use technologies become competitive relative to thermal generation
Consumer Perceptions	• Drought is visible and bad enough to focus public attention on significant restrictions (and associated costs) in water use on an industrial scale • Impact of the drought overcomes in large part consumers cost sensitivity

Scenario Summary – Infrastructure Attacked

Scenario Summary	Both physical and cyber intrusions are systematically conducted against the nation's infrastructure. The federal government makes significant and rapid policy changes in the area of cyber-security. Public perception of the cost/reliability shifts heavily to reliability.

Driver	Scenario Outcome
Environmental / General Regulation & Legislation	• Security regulations drive new standards and regulations that significantly impact the energy industry
Commodity Prices	• Disruption driven scarcity pricing in the very near term relative to the intrusions • Incremental price pressure in the longer term due to security and reliability requirements
Economic Growth	• Disrupted on a very short term basis with return to modest growth • Energy industry become a focus for security related investments in both physical and cyber infrastructure
Technological Innovation	• Significant investment in physical and cyber security infrastructure drives innovation and technology development • Gas pipeline and electric transmission reliability standards drive investment • Gas and electric flexibility, diversity, and de-centralization becomes critical – distributed generation makes significant penetration into the market
Consumer Perceptions	• Consumers feel a significant impact from the disruptions in the near term • Consumers demand and vigorously pursue more reliability, often in distributed or de-centralized technology (on site generation, fuel cells, PV solar, etc.)

Next Steps

- Finalize the drivers that will be varied in the final modeling representation of the scenarios
- Determine if there are any “secondary” drivers that may need to be varied as well to round out the scenario modeling
- Develop and finalize the trajectory of the varied drivers
- Develop and document any fact patterns necessary to support the varied driver trajectories

APPENDIX

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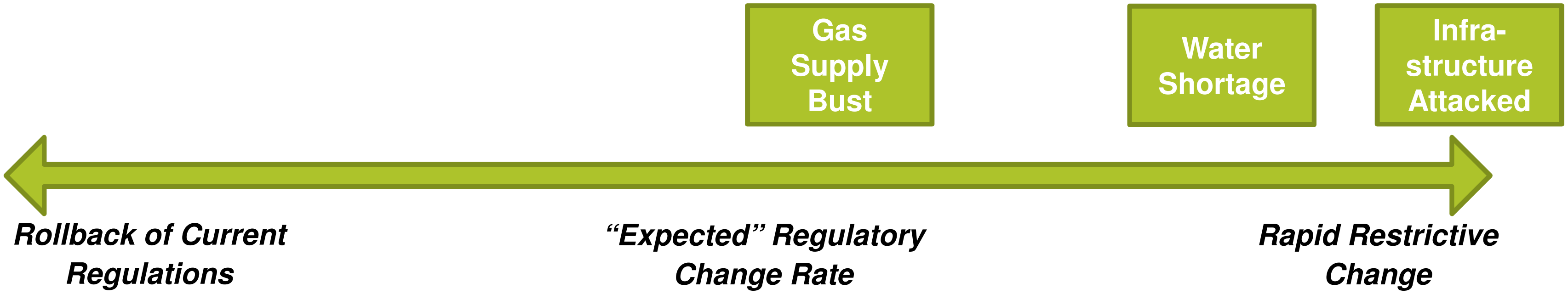
Expected Case summary

Driver	Group 1	Group 2	Group 3
Environmental / General Regulation & Legislation	• Continued uncertainty with a tendency towards more restrictive but limited by cost pressure	• More “green” overall with pressure on emission regs. • Water use becomes more constrained • Higher security (physical & IT) standards	• Regulations continue to pressure/restrict coal • Closed loop cooling mandated • PTC goes away w/in 10 yrs • EE/DR widely promoted
Commodity Prices	• \$5-\$7/MMBtu real gas prices • Oil continues high	• \$5-\$7/MMBtu real gas prices • Oil continues high	• \$4-\$5/MMBtu real gas prices with \$6/MMBtu as a cap • Oil continued high • Ag prices pressure to upside
Economy / Growth	• 1%-2% load growth overall from low energy costs • Pockets of higher and lower growth across region	• 1%-2% load growth overall • Industrial growth drives demand with some offset from R & C conservation	• 1% - 1.5% over all demand growth but uneven over footprint (west higher)
Technological Innovation	• Not Documented / not a factor	• Shut down older coal & shift to gas on the margin • No new coal or nuclear • %5 increase in wind energy mix • No DG impact	• Limited, gas replaces coal at the margins • EE / DR advances with regulatory support
Consumer Perceptions	• Structural problems in the economy remain unsolved • Consumers challenged economically	• At risk with SPP members in case of large scale data loss	• Modest push back on cost / mandates / regulations • No significant alternatives to the current energy model

Environmental / General Regulation & Legislation – Observations & Signposts



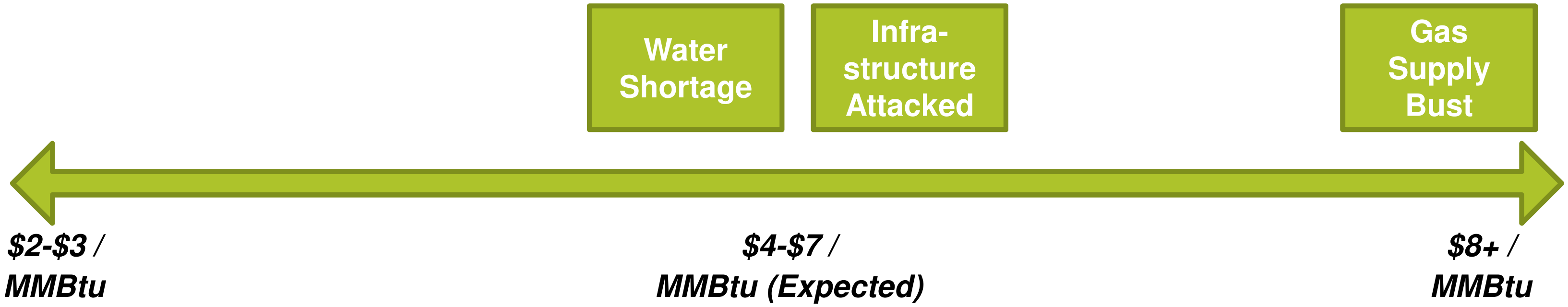
OBSERVATIONS

- In the expected case and in each of the scenarios, a rollback in regulations as they currently exist is not contemplated
- Each of the scenarios can be viewed as describing the impact of a variety of different but “aggressive” regulatory programs

POTENTIAL SIGNPOSTS

- Change in administration (2 elections in the time frame)
- Change of congressional (either House of Senate) control
- Significant events related to the environment resulting from man-made activities
- Consumer (voter) sentiment evolution
- Significant change in current economic conditions

Commodity Prices (natural gas) – Observations & Signposts



OBSERVATIONS

- In all of the scenarios, the price spread (3x to 4x) between natural gas and oil is maintained
- All of the scenarios anticipate price pressure to the high side for agricultural products
- Persistently low natural gas prices (<$4/MMBtu) are not considered relevant and/or likely enough for scenario consideration

POTENTIAL SIGNPOSTS

- External events related to fracking activities
  - Earthquakes
  - Contamination
  - Geo-political
- Technological innovation
- Global development of shale extraction techniques
- Shocks to other commodities (copper, steel, concrete, etc.)

Economic Growth (SPP load growth) – Observations & Signposts

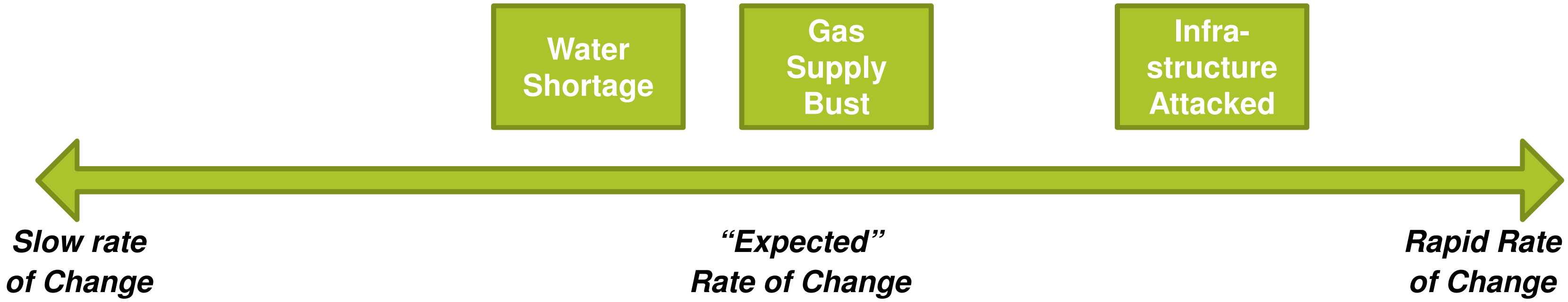
OBSERVATIONS

- Growth rates shown are averages and reflect a range of higher growth areas (Ag, E&P) and lower growth areas
- None of the scenarios anticipates growth rates significantly greater than is currently expected
- Significant growth improvement on an economy-wide basis is not contemplated in any of the scenarios

POTENTIAL SIGNPOSTS

- Geo-political events
- Change in regulations
- Technological innovation, particularly in E&P business
- Technological change – superconducting transmission, distributed generation, advanced manufacturing, etc.
- Major change in water availability

Technological Innovation – Observations & Signposts



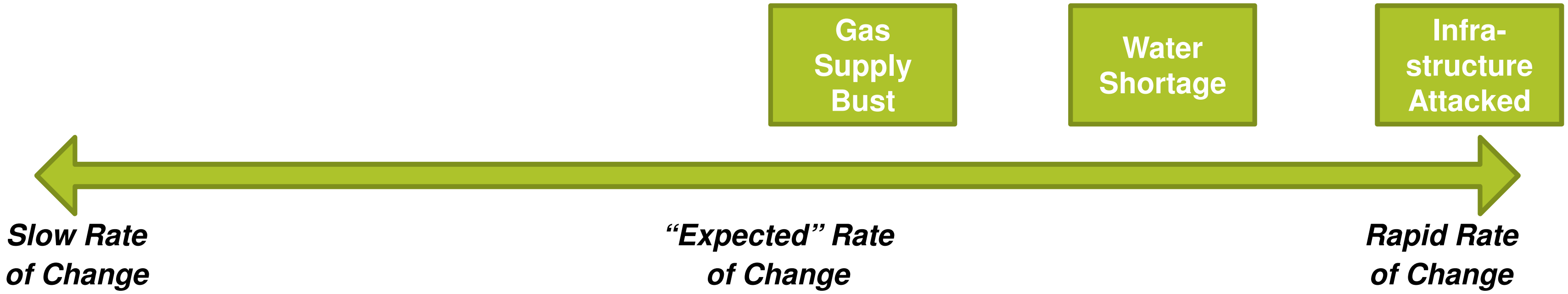
OBSERVATIONS

- The scenarios do not contemplate technological innovation as an "initiator" event driving all other outcomes
- The rate of change considered in the scenarios is well short of transformational in nature
- The fundamental/competitive nature of the current generating model is not materially challenged in any of the scenarios

POTENTIAL SIGNPOSTS

- Advances in key foundational sciences:
  - Physics, chemistry, materials
  - Etc.
- Step change in transformative technologies
  - Solar panel prices / efficiency
  - Fuel cells
  - Superconducting transmission
  - Etc.

Consumer Perceptions (change in sentiment, demand for new products & services, etc.) – Observations & Signposts



OBSERVATIONS

- The scenarios do not contemplate consumer sentiment as an "initiator" event driving all other outcomes
- The consumer is never offered an "alternative" to the current energy delivery model (10 year time frame is too short)

POTENTIAL SIGNPOSTS

- Direction of the "culture"
  - Media & Entertainment
  - Educational focus
- Instances / areas of high technology advancement / adoption rates
  - Communication
  - Transportation
  - Entertainment
- Energy technology "breakthroughs"

BRIDGE STRATEGY GROUP was founded in 1998 with a sole purpose: help executives solve their most pressing business issues — not simply prepare plans.

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