Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

February 18th – 19th, 2015

Embassy Suites Riverwalk-Downtown, San Antonio, TX

• SUMMARY OF ACTIONS TAKEN •

1. Approved the December 11th and December 15th minutes.
2. Endorsed the 2014 Capacity Margin LOLE Report.
3. Approved a motion directing staff to resolve the RCAR II Trapped Generation Pockets issue (issue 1) with Option 1D, a hybrid approach that redistributes zonal benefit as a percentage share of the regional benefit.
4. Approved a motion directing staff to resolve the RCAR II Load Pocket issue (issue 2) with Option 2c, adding CTs in base and change cases, and making them non-dispatchable in change case.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

February 18th – 19th, 2015

Embassy Suites Riverwalk-Downtown, San Antonio, TX

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains) called the meeting of the Economic Studies Working Group (ESWG) to order at 1:00 PM, welcomed those in attendance, and asked for introductions.

There were 24 in-person participants and 36 web conference participants representing 11 of 13 ESWG members. (Attachment 1 – February 18th – 19th, 2015 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. Two proxies were identified; Kip Fox (AEP-Transource) named Wayman Smith (AEP) as his proxy. Don Le (NextEra) named Kip Fox (AEP-Transource) as his proxy. (Attachment 2 – Proxy Statements)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – February 18th -19th, 2015 Agenda)

Kurt Stradley (LES) made a motion; seconded by Pat McCool (KCPL) to adopt the agenda. The motion was approved unanimously.

Agenda Item 2 – Review of Past Action Items

Juliano Freitas (SPP Staff) reviewed the list of past action items with the group. All items from the December 2014 meeting were marked complete. Juliano informed the group that staff will begin item 57 regarding development of a resource siting process shortly. (Attachment 4 – Past Action Items)

Agenda Item 3 – Consent Agenda

The Consent Agenda included the following item:

Approval of Meetings Minutes –December 11th, 2014 (Attachment 5 – ESWG 12.11.14 Minutes)
Approval of Meetings Minutes –December 15th, 2014 (Attachment 5 – ESWG 12.15.14 Minutes)

The consent agenda was approved unanimously.

Agenda Item 4 – Study Schedules

Agenda Item 4a – 2017 ITP10

Juliano Freitas (SPP Staff) gave an update on the status of the 2017 ITP10. Staff will look into pushing the dates out for the renewable resource plan, to allow time to incorporate the 111D ruling. (Attachment 6 - 2017 ITP10 Schedule)

Agenda Item 4b – RCAR II

Juliano Freitas (SPP Staff) gave an update on the status of the RCAR II. Staff informed the group that the TWG approved the powerflow model earlier that day. (Attachment 7 – RCAR II Schedule)

Agenda Item 4c – SPP-MISO CSP

Juliano Freitas (SPP Staff) gave an update on the status of the SPP-MISO CSP Study. SPP and MISO are currently working on reliability needs and economic projects screening. (Attachment 8 – SPP-MISO CSP Schedule)

Agenda Item 5 – BRP059

Ben Bright (SPP Staff) gave a presentation in BPR059, the Competitive Upgrade Request for Proposal (RFP) Issuance. The purpose of this business practice is to describe the process and timeline for the creation and issuance of a Request for Proposal (RFP) for a Competitive Upgrade. The RFP process is part of the larger Transmission Owner Selection Process (TOSP), which is the process of determining the Transmission Owner for Competitive Upgrades. RFPs will be issued for each Competitive Upgrade approved for construction by the SPP Board of Directors (BOD) for which SPP staff will issue a Notification to Construct (NTC). (Attachment 9 – BRP059)

Agenda Item 6 – 2014 Capacity Margin LOLE Report

Michael Odom (SPP Staff) presented the results of the 2014 Capacity Margin LOLE Report. This study provides an assessment of whether currently installed capacity is adequate to serve the forecasted load. The presentation included an overview of the study inputs and assumptions, descriptions of the data, and the study results. The findings were that the Loss of Load Expectation (LOLE) Per the SPP Criteria and industry standard is one day in 10 years (0.1 day/year). Daily LOLE is the expected daily occurrences of the loss of load throughout the year. SPP Staff recommended that the ESWG endorse the 2014 Capacity Margin LOLE Report as documentation of completion of the 2014 Capacity Margin LOLE study as specified in SPP Criteria section 4.3.5. (Attachment 10 – 2014 Capacity Margin LOLE)

> **Kip Fox (AEP-Transource) made a motion; seconded by Pat McCool (KCPL) to endorse the 2014 Capacity Margin LOLE report as documentation of completion of the 2014 Capacity Margin LOLE study as specified in SPP criteria section 4.3.5. The motion passed unanimously.**

Agenda Item 7 – ITP Process Improvements

Amber Greb (SPP Staff) gave a presentation on the ITP Process Improvement. Staff is looking for opportunities to save time and reduce errors in the ITP process through automation, documentation and better communication. (Attachment 11 – ITP Process Improvement)

Agenda Item 8 – 2017 ITP10 Futures

Discussion picked up from the previous meeting with members discussing the appropriate number of futures. The group settled on starting with more futures and possibly eliminating some through further refinement. The main driver of the number of futures was the 111D ruling. The group decided on four futures around this driver: Future 1 – a regional solution for 111D, Future 2 – A state level solution to 111D, Future 3 – 111D is not considered, and Future 4 – A worst case scenario with a high carbon tax.

Additional drivers were then discussed in terms of each of these 4 futures. For Example, a sub $24 price for the competitive wind driver was decided on for futures 1-3, while considering an increase in wind prices for future 4. A table was developed to capture this discussion and the decisions made. (Attachment 12 – Futures Discussion)

ACTION ITEM: SPP Staff to send the ESWG a summary of the 2017 ITP10 Futures Discussion.

Agenda Item 9 – RCAR II Analysis

Josh Ross (SPP Staff) presented on the RCAR II model. On January 29th, Staff presented two issues with the model to the group. Additional analysis was requested. Staff brought the preliminary results of this analysis to the meeting for discussion. The group discussed issue #1: Trapped Generation Pockets. West KS zones are showing negative APC savings, even though their more expensive generation is being displaced with cheaper generation in the change case. Staff presented 5 options to solve the issue. After discussing the results of each option (staff did not have time to get results for the 5th option), the group voted to implement the 4th option. Option 1d, the hybrid approach, takes the APC calculated

with wind in both the base and change cases (which is a good approach for calculating regional benefit), then allocates the APC to the zones based on the percent share of benefit per zone with the wind taken out of the model.

The group then discussed the second issue with the model: Load Pockets. The Load pocket does not have enough transmission to serve load in base case. Excessive emergency gen and breaching constraints are causing high LMPs in the base case, resulting in high APC savings. Staff presented four possible solutions to the issue. The group discussed and decided on option 2c, which adds CT's in the base and chance case and making them non-dispatchable in the change case. (Attachment 13 – RCAR II Analysis)

Paul Dietz (Westar) made a motion; seconded by Tim Owens (NPPD) that in the interest of maintaining the current schedule, the ESWG recommends that the RARTF proceed with option 1d. The motion passed with two no votes, Wayman Smith (AEP) and Bennie Weeks (SPS), and two abstentions, Al Tamimi (SUNC) and Pat McCool (KCPL). Al Tamimi (SUNC) abstained from voting due to the following reasons: 1) it does not factor in congestion impact on Sunflower. Most of the time, congestion happens when our system load at its lowest point, and since Sunflower has over 220MW of wind contracts that when the LMP's go negative Sunflower is harmed too since Sunflower does not have the load level to absorb 221 MW of wind; 2) not knowing the results of the last method "Incremental method" made him lean toward abstaining.

Bennie Weeks (SPS) made a motion; seconded by Paul Dietz (Westar) to recommend using option 2c, adding CT's into the base and change cases, and making them non-dispatchable in the change case. The motion passed unopposed.

Agenda Item 11 – Renewable Survey Improvements

Liz Gephardt (SPP Staff) gave an update on the ITP10 Renewable Survey Process Improvements. Since ESWG and CAWG both wanted to discuss policy level issues before moving forward with process improvements, Staff is working internally to develop options and a recommendation to present at the March meeting.

Agenda Item 12 – 2017 ITP10 Study Methodology

Chris Jamieson (SPP Staff) introduced himself as the staff leader of the 2017 ITP10 Study. Juliano Freitas (SPP Staff) presented on the 2017 ITP10 Study Methodology. The planned study year for the 2017 ITP10 is 2026. Staff brought to the attention of the group, the decision points that will soon be coming up for discussion. Currently the biggest topic is the futures, determining the number of futures to use and the major inputs of those futures. Up next will be the renewable survey, the load and generation review, and the resource plan. The group discussed the changes to the load and generation review and brought up some issues. Kelsey Allen will have an offline discussion with some members to continue the discussion. (Attachment 14 – 2017 ITP10 Study Methodology)

ACTION ITEM: SPP Staff to bring the 2017 ITP10 Study Methodology back to the group in March, for more discussion on the load and generation review.

Closing Items

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

Chair Alan Myers (ITC Great Plains) requested that members begin thinking about a review of the ESWG charter and membership criteria.

List of action items from the meeting:

1. SPP Staff to send the ESWG a summary of the 2017 ITP10 Futures Discussion.
2. SPP Staff to bring the 2017 ITP10 Study Methodology back to the group in March, for more discussion on the load and generation review.

The meeting was adjourned at 11:55 AM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

ESWG
2/18/15
Sign In

1) Amber Greb — SPP
2) Juliano Freitas — SPP
3) Ben Bright — SPP
4) Wayman Smith — AEP — Kip's Proxy
5) Bruce Rodle — Xcel
6) Jason Schmidt — Xcel
7) Jordan Schmick — Xcel Energy/SPS
8) Walt Cecil — MoPSC
9) Michael Wagner — ITC
10) Michael Odom — SPP Staff
11) Kurt Stradley — LES — M
12) Tim Owens — NPPD — M
13) Alan Myers — ITC — M

14) Kip Fox — AEP — Don's Proxy
15) Paul Dietz — Westar Energy — M
16) Pat McCool — KCPL — M
17) Bennie Weeks — Xcel/SPS — M
18) Steve Gaw — Wind Coalition
19) TIM SOLES — OCCIDENTAL
20) Pat Hayes — Ameren
21) Kaustubh Deshmukh — ITC
22) GRIMOD OLAPURAYIL — ITC
23) JOHN BELL — KCC
24) Meena Thomas — Texas
25)
26)
27)
28)
29)
30)
31)

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Meena Thomas	meena.thomas@puc.texas.gov

1. Kip Fox (AEP Transource) proxy to Wayman Smith (AEP)

From: Kip M Fox [mailto:kmfox@aep.com]
Sent: Wednesday, February 18, 2015 12:35 PM
To: Myers, Alan; Juliano Freitas
Cc: Smith, Wayman
Subject: Proxy

Please allow this email to have Planning Expert Wayman Smith act as my proxy for 2/19/15.

Thank you, Kip

Kip Fox

2. Don Le (NextEra) proxy to Kip Fox (AEP-Transource)

From: Le, Don [mailto:Don.Le@nexteraenergy.com]
Sent: Tuesday, February 17, 2015 3:10 PM
To: Juliano Freitas; Kelsey Allen; Fox, Kip
Subject: Proxy

The almighty Mr. Kip Fox has my proxy for the next two ESWG meetings as I'm at home taking care of a newborn.

I don't think you guys want a baby crying in the background again!! Hope all is well!

Don Le
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NextEra Energy Transmission
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ECONOMIC STUDIES WORKING GROUP

February 18th - 19th, 2015

Embassy Suites Riverwalk-Downtown, San Antonio, TX

• A G E N D A •

Wednesday 1:00 pm – 5:00 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[1] ..... Kelsey Allen (5 minutes)
3. Consent Agenda (Approval Item) [1] ..... Alan Myers (5 minutes)
    a. Approval of Meeting Minutes – December 11th, 2014
    b. Approval of Meeting Minutes – December 15th, 2014
4. Study Schedules[1] ..... Juliano Freitas (15 minutes)
    a. 2017 ITP10
    b. RCAR II
    c. SPP-MISO CSP
5. BPR059[1] ..... Ben Bright (45 minutes)
6. 2014 Capacity Margin LOLE Report[1] (Approval Item) ..... Michael Odom (30 minutes)
7. ITP Process Improvement[1] ..... Amber Greb (30 minutes)
8. 2017 ITP10 Futures[1] ..... All (90 minutes)

Thursday 8:00 am – 12:00 pm

9. RCAR II Analysis ..... Juliano Freitas/Josh Ross (60 minutes)
10. 2017 ITP10 Futures Continued[1] ..... All (90 minutes)

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[1] Background materials included

11. Renewable Survey Improvements ..... Liz Gephardt (30 minutes)

    a. CAWG Feedback

    b. Next Steps

12. 2017 ITP10 Study Methodology[1] ..... SPP Staff (30 minutes)

13. Closing Items ..... All

[1] Background Material Included

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

February 18th, 2015

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 March/April 2015.
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
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	
140	SPP Staff to send the ESWG a synopsis of the RARTF discussion regarding the ESWG's request for more time in the RCAR II schedule after that group's December meeting.	December 11, 2014	Complete	The RARTF recommended extending the RCAR II Final Report approval to July 2015 in order to provide members more time to review models, data and provide feedback. The RARTF requested that preliminary remedy recommendations be given to the RARTF no later than May 2015.
141	Staff will determine and report back to the ESWG expectations on leveraging the information gathered during the SPP-MISO CSP study to improve the modeling of external systems in the 2017 ITP10	January 29th, 2015	In Progress	
142	Staff will work with Ventyx to determine a schedule and details for a PROMOD User's Group meeting to be hosted by SPP.	January 29th, 2015	In Progress	

143	Staff to frame a discussion for a future meeting regarding rules of adding renewable generation capacity beyond policy requirements.	January 29th, 2015	In Progress	To be discussed at the March 31 meeting.
144	Paul Dietz to summarize the Futures discussion to date and send out to the ESWG with a deadline for comments.	January 29th, 2015	~~In Progress~~Complete	
145	SPP Staff to send the ESWG a summary of the 2017 ITP10 Futures Discussion.	February 18th, 2015	In Progress~~Complete~~	
146	SPP Staff to bring the 2017 ITP10 Study Methodology back to the group in March, for more discussion on the load and generation review.	February 18th, 2015	In Progress	

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Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

December 11th, 2014

AEP Offices 8th Floor, Dallas, TX

• SUMMARY OF ACTIONS TAKEN •

1. Approved the November 20th minutes.
2. Approved SPP Staff's completion of the 2015 ITP10 project staging process.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

December 11th, 2014

AEP Offices 8th Floor, Dallas, TX

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains) called the meeting of the Economic Studies Working Group (ESWG) to order at 9:30 AM, welcomed those in attendance, and asked for introductions.

There were 11 in-person participants and 47 web conference participants representing 11 of 13 ESWG members. (Attachment 1 – December 11th, 2014 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. One proxy was identified; Kip Fox (AEP-Transource) named Wayman Smith (AEP) as his proxy. (Attachment 2 – Proxy Statements)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – December 11th, 2014 Agenda)

Paul Dietz (Westar) made a motion to adopt the agenda. 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 past action items with the group. All items from the November meeting were marked complete. Kelsey Allen requested additional time for action item 057 regarding a straw man for generation siting in the ITP process. The group agreed to allow staff to bring a first draft to the March/April ESWG meeting. (Attachment 4 – Past Action Items)

Agenda Item 3 – Consent Agenda

The Consent Agenda included the following item:

Approval of Meetings Minutes – November 20th, 2014 (Attachment 5 – ESWG 11.20.14 Minutes)

The consent agenda was approved unanimously.

Agenda Item 4 – Study Schedules

Agenda Item 4a – 2015 ITP10

Juliano Freitas (SPP Staff) gave an update on the status of the 2015 ITP10. Staff will be presenting on the Project Staging, Metrics and Sensitivities in the meeting today. The report is scheduled to be completed and sent out December 26th. Staff requested the group be prepared for potential email approval by January 2, 2015. (Attachment 6 - 2015 ITP10 Schedule)

Agenda Item 4b – RCAR II

Juliano Freitas (SPP Staff) gave an update on the status of the RCAR II. The RARTF has not yet discussed the ESWG motion requesting additional time in the schedule for data and results review. The RARTF is scheduled to meet December 19th and will be discussing the request then. (Attachment 7 – RCAR II Schedule)

ACTION ITEM: SPP Staff to send the ESWG a synopsis of the RARTF discussion regarding the ESWG's request for more time in the RCAR II schedule after that group's December meeting.

Agenda Item 4c – SPP-MISO CSP

Juliano Freitas (SPP Staff) gave an update on the status of the SPP-MISO CSP Study. SPP and MISO are currently working on solution development and screening. The next IPSAC meeting is scheduled to be held February 16, 2015. The group asked about the purpose of a reliability assessment in the CSP study. Brett Hooton (SPP Staff) explained that SPP and MISO will be looking for issues not seen before with a new model and potential opportunity to work with MISO or an individual MISO Transmission Owner on project development. MISO may also investigate developing a process to cost share a project that is beneficial to both regions that doesn't currently meet the defined criteria. (Attachment 8 – SPP-MISO CSP Schedule)

Agenda Item 5 – 2015 ITP10

Agenda Item 5a – Staging

Rosemary Mittal (SPP Staff) presented process and results of the project staging portion of the 2015 ITP10. This included a list of projects meeting criteria to be recommended for NTCs, highlighting changes made after the November 20th staging presentation. SPP Staff recommended the ESWG to approve Staff's completion of the 2015 ITP10 staging process. (Attachment 9 – 2015 ITP10 Staging)

> **Kurt Stradley (LES) made a motion; seconded by Leon Howell (OGE) that the ESWG approve SPP Staff's completion of the 2015 ITP10 project staging process. The motion passed unanimously.**

Agenda Item 5b – Metrics

Josh Ross (SPP Staff) presented the results of the 2015 ITP10 benefit metric calculations. The metrics were calculated on the full portfolio of projects, regardless of whether a project will be issued an NTC. The group gave good feedback to Staff regarding additional clarity and information that needs to be included in future presentations and the final report. (Attachment 10 – 2015 ITP10 Metrics)

Agenda Item 5c – Sensitivities

Kelsey Allen (SPP Staff) presented results of the 2015 ITP10 sensitivity analysis. The sensitivities were calculated on the full portfolio of projects, including those designated as reliability only. The group gave good feedback to Staff regarding additional clarity and information that needs to be included in future presentations and the final report. (Attachment 11 – 2015 ITP10 Sensitivities)

Agenda Item 7 – 2017 ITP10 Futures

Alan Myers (ITC Great Plains) and Paul Dietz (Westar) described the work that they have done on the drivers considered in the Futures discussion. The drivers were grouped and molded into potential Futures considering two different methodologies. The first was a "primary influence spheres" approach where only certain like drivers were grouped together to form a potential Future. Drivers were put into an Environmental, Financial, and/or Operational sphere. The second approach involved assuming a level of change for each driver to develop a low change high change and extreme change scenario, considering each driver at a certain increase or decrease. Both of these approaches assume change to an expected case that will have to be developed. Each driver being considered in the Futures development will have to be evaluated for its impact in an expected, historically "Business as Usual", scenario that will serve as a pivot point to develop other Futures.

There was much discussion by the group around how to accomplish this development and provide a useful message to other groups that will be involved in the process (MOPC, SPC). Some stakeholders expressed concern that we do not have definitions for Futures and the need for analysis to help shape what those definitions might be. At this point the group is not far enough along in discussions to make those types of determinations. In moving forward, the group must determine what each percentage of change means as well as conflicting drivers and how to implement those in each scenario.

For discussion with the MOPC and SPC, the group decided to take the information in a phased approach and cover all items discussed: Discussion of the drivers, discussion of the influence spheres, and discussion of other implied change Futures. (Attachment 12 – 2017 ITP10 Futures Priority_rev2)

Agenda Item 7 – ITP Manual Review

This item will be covered in a conference call to be scheduled for Monday, December 15th, 8:00 am – 10:00 am.

Agenda Item 8 – 2014 Organizational Group Survey

This item will be covered in a future meeting.

Closing Items

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

List of action items from the meeting:

1. SPP Staff to send the ESWG a synopsis of the RARTF discussion regarding the ESWG's request for more time in the RCAR II schedule after that group's December meeting.

The meeting was adjourned at 3:30 PM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

December 15th, 2014

Net Conference

• SUMMARY OF ACTIONS TAKEN •

1. None

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

December 15th, 2014

Net Conference

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:03 AM, welcomed those in attendance, and asked for introductions.

There were 26 web conference participants representing 9 of 13 ESWG members. (Attachment 1 – December 15th, 2014 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements.

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains) presented the agenda for review and asked for any additions or corrections. (Attachment 2 – December 15th, 2014 Agenda)

> **Paul Dietz (Westar) made a motion; seconded by Wayman Smith (AEP) to adopt the agenda. The motion was approved unanimously.**

Agenda Item 2 – ITP Manual Review

Paul Dietz (Westar) walked the group through the changes to the ITP Manual made by the Task Force and asked for feedback. Some of the sections changed were accepted by the group, some discussed and reworded, and some left open for more language to be added. The group will discuss more at the next meeting in order to pass on to the TWG for review. SPP Staff will (Attachment 3 - ITP_Manual - Task Force - combined edits_v3)

Agenda Item 3 – 2014 Organizational Group Survey

This item will be covered in a future meeting.

Closing Items

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

The meeting was adjourned at 10:00 AM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

2017 ITP10 Schedule

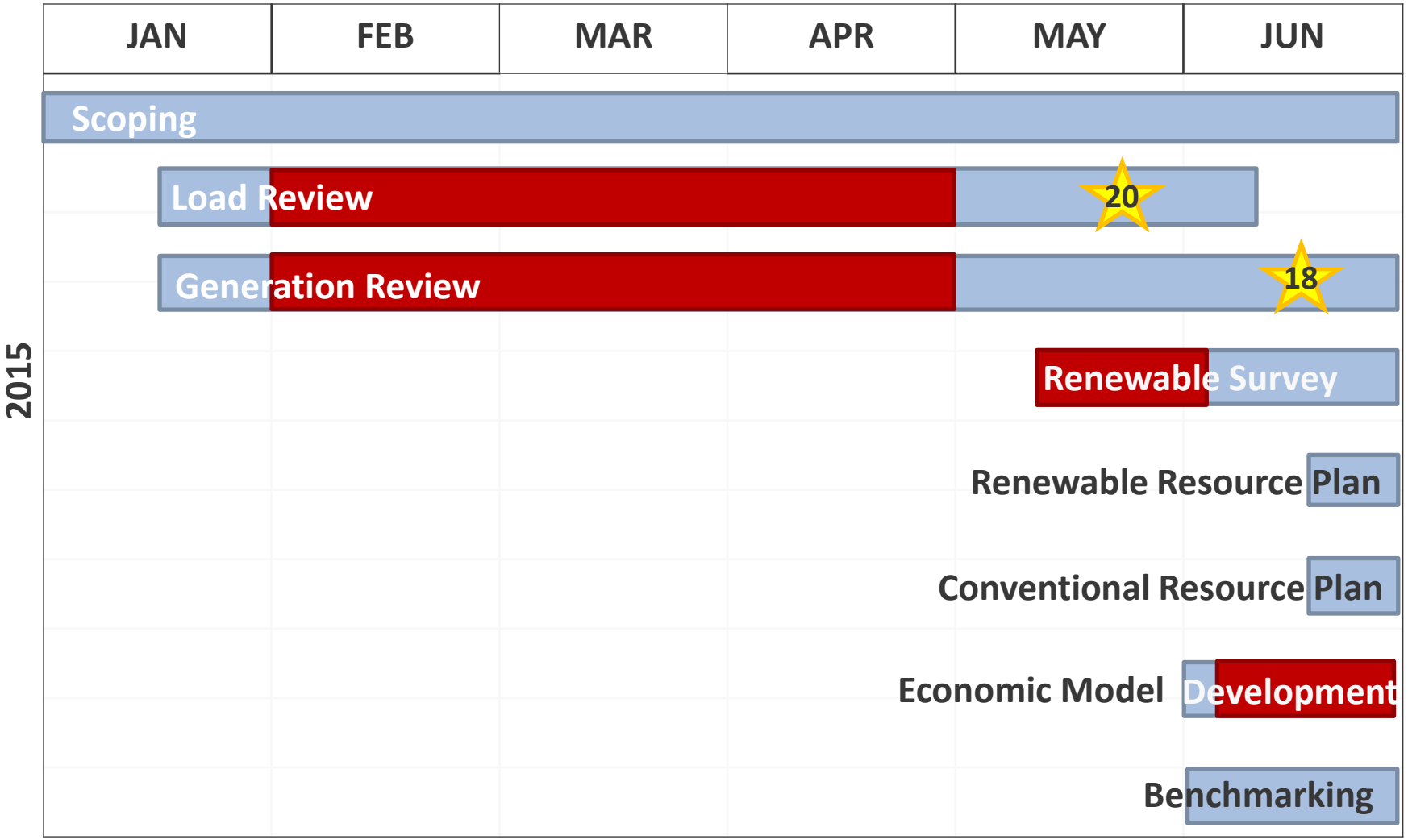
February 18th, 2015

ESWG

Juliano Freitas

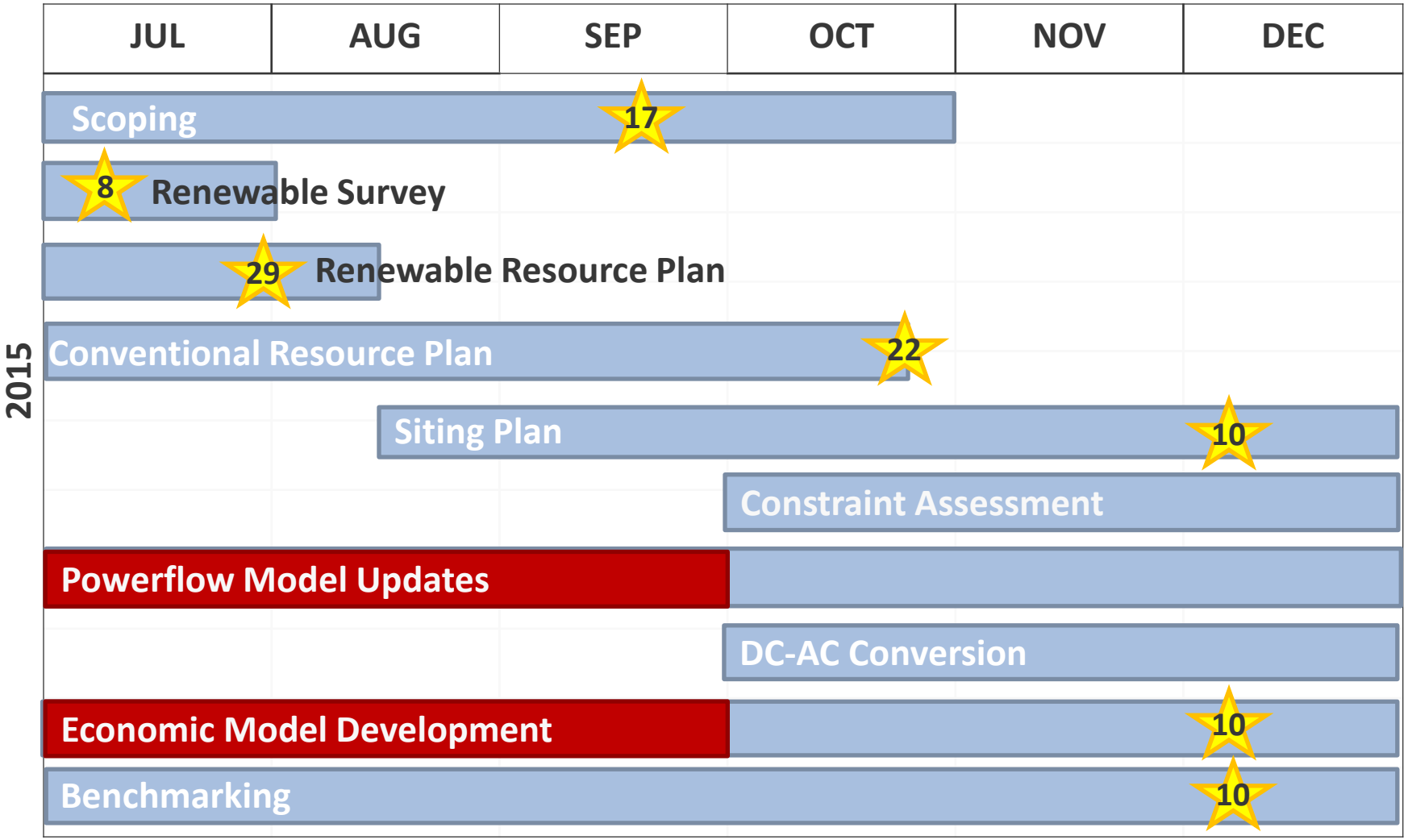
SPP Southwest Power Pool

ITP10 Milestone Schedule (Jan-Jun 2015)



ESWG Approval | Member Review/Feedback Period | Milestone Period

ITP10 Milestone Schedule (Jul-Dec 2015)



ITP10 Milestone Schedule - Summary

Task Name	Start	Finish	Member Feedback	ESWG Approval
Scoping	October '14	October '15	Multiple Reviews	9/17
Load Review	February	June	10 Weeks	5/20
Generation Review	February	July	10 weeks	6/18
Renewable Survey	May	July	5 weeks	7/8
Renewable Resource Plan	June	August	2 weeks	7/29
Conventional Resource Plan	June	October	5 weeks	10/22
Siting Plan	August	December	2 weeks	12/10
Powerflow Model Development	July	April '16	5 weeks	April '16
Benchmarking	June	December	3 weeks	12/10
Economic Model development	June	January '16	7 weeks	1/26/16
Constraint assessment - TWG Approval	August	January '16	2 week	1/26/16
DC to AC Conversion of Peak Hours	October	April '16	2 weeks	April '16

2015

RCAR II Schedule

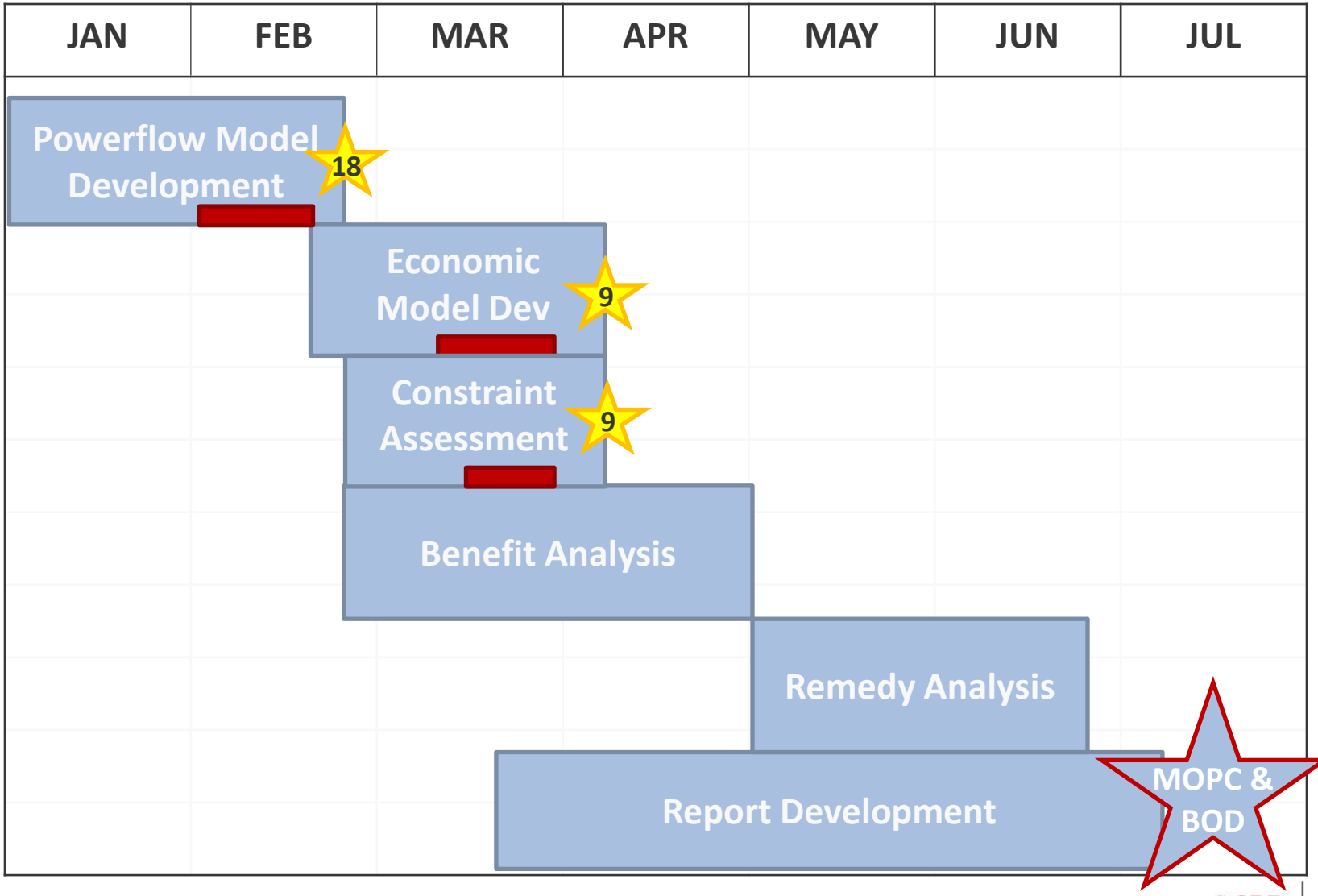
February 18th, 2015

ESWG

Juliano Freitas

SPP Southwest Power Pool

RCAR II Milestone Schedule (January – July 2015)



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

RCAR II Milestone Schedule - Summary

Task Name	Start	Finish	Working Group Review/Feedback	Working Group Approval
Powerflow Model Development	January 2	February 18	1/29-2/12	February 18
Economic Model Development	February 18	April 9	3/9-3/30	April 8
Constraint Assessment	February 25	April 9	3/16-3/30	April 8
Benefit Analysis	February 18	May 1	--	--
Remedy Analysis	May 1	June 23	--	--
Report Development	March 16	June 30	--	July MOPC/BOD

2015

SPP-MISO CSP

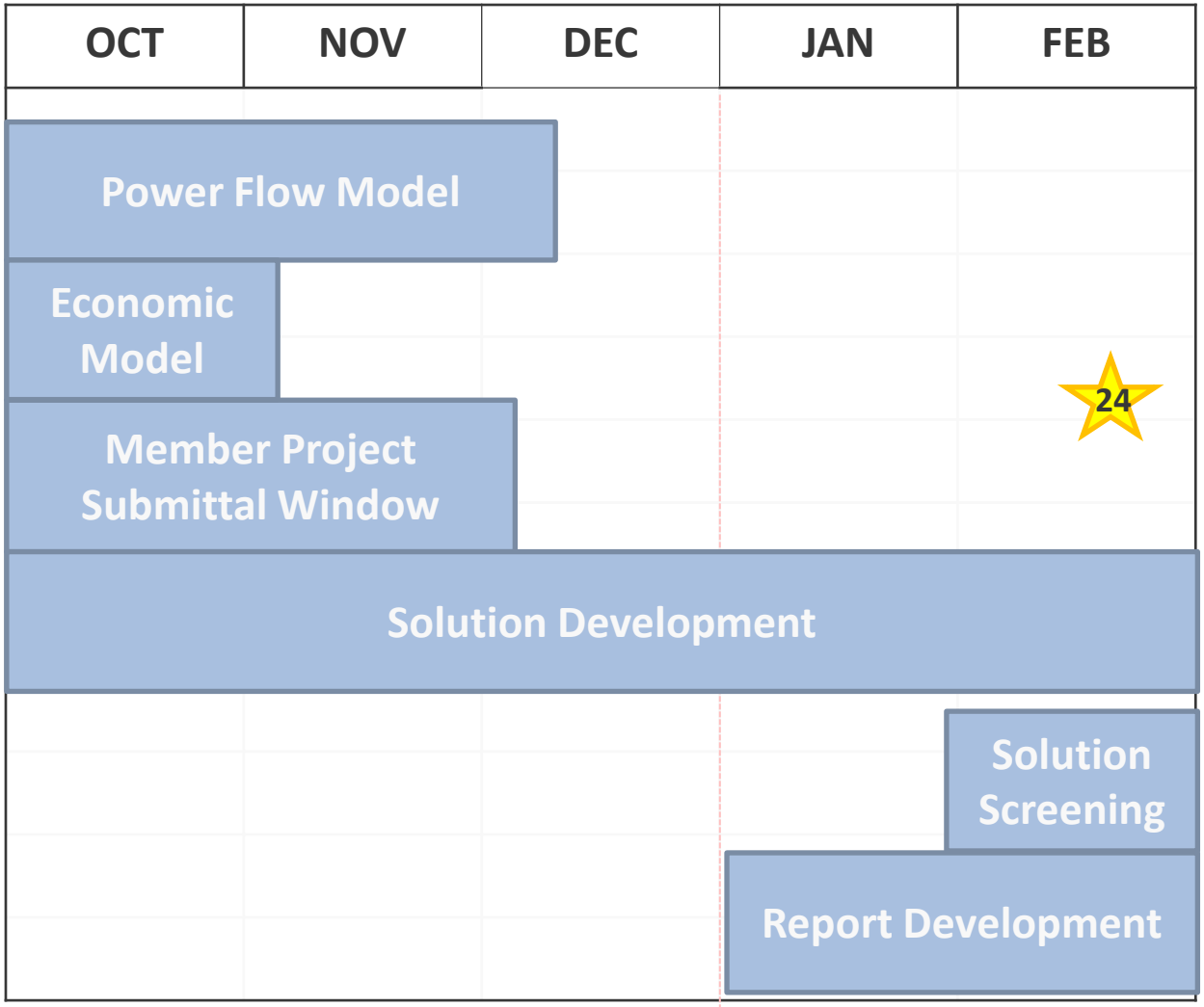
February 18th, 2015

ESWG

Juliano Freitas

SPP Southwest Power Pool

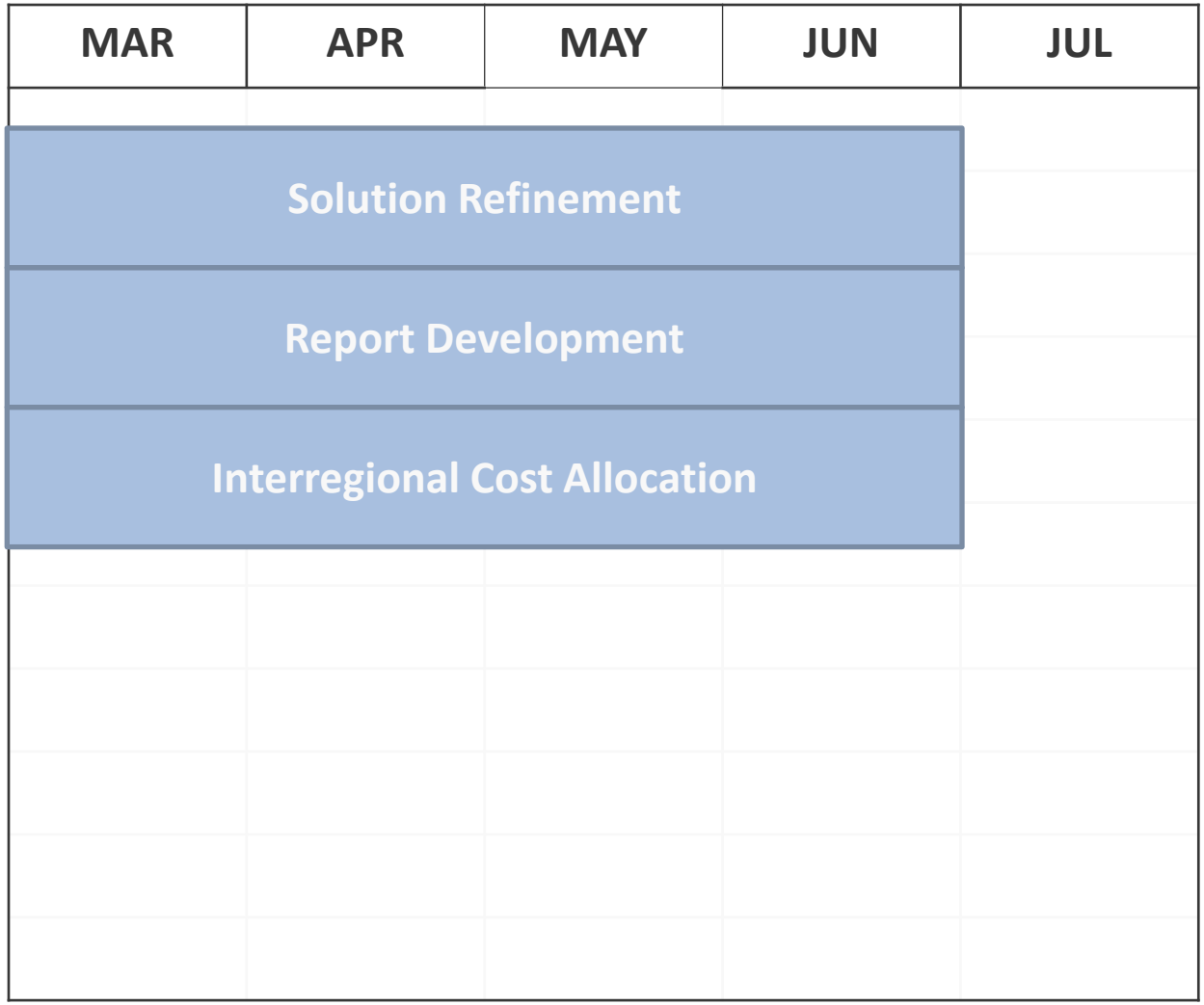
MISO SPP CSP Milestone Schedule (Oct 2014-Feb 2015)



Stakeholder Meeting

Milestone Period

MISO SPP CSP Milestone Schedule (Mar-Jun 2015)



Stakeholder Meeting

Milestone Period

BPR Number	BPR 059	BPR Title	Competitive Upgrade Request for Proposal (RFP) Issuance
Business Practice Section(s) Requiring Revision (include Section No., Title, and Protocol Version)		7700	
Impact Analysis Required (Yes or No)		No	
MMU Report Required (Yes or No)		No	
Requested Resolution (Normal or Urgent)		Urgent	
Revision Description		This updated business practice adds the process for the Order 1000 Request for Proposal (RFP) in the Transmission Owner Selection Process (TOSP) under Attachment Y as it relates to RFP issuance and receipt.	
Reason for Revision		This is part of the new processes resulting from SPP's Tariff revisions to comply with FERC Order 1000.	
Tariff Implications or Changes (Yes or No; If yes include a summary of impact and/or specific changes)		?	
Criteria Implications or Changes (Yes or No; If yes include a summary of impact and/or specific changes)		No	
Credit Implications (Yes or No, and summary of impact)		No	

Working Group/Committee Review and Results	BPWG – February 9, 2015 (Initial Review) ORWG – RTWG – February 26, 2015 PCWG – February 4, 2015 ESWG –February 18, 2015 TWG –February 18, 2015 MOPC – April 15, 2015

Sponsor	
Name	Michael Desselle
E-mail Address	mdesselle@spp.org
Company	SPP
Company Address	201 Worthen Dr. Little Rock, AR 72223
Phone Number	501-614-3206
Fax Number	

Proposed Business Practice Language Revision

7700 Order 1000: Competitive Upgrade Request for Proposal (RFP) Process

Business Practice

The purpose of this business practice is to describe the process and timeline for the creation and ~~publication~~issuance of a Request for Proposal ("RFP") for a Competitive Upgrade as outlined in Attachment Y, Section III of the SPP Tariff. The RFP process is part of the larger Transmission Owner Selection Process ("TOSP"), which is the process of determining the Transmission Owner for Competitive Upgrades according to Section III.2 of Attachment Y of the Tariff. RFPs will be issued for each Competitive Upgrade approved for construction ~~or endorsed~~ by the SPP Board of Directors ~~(~~("BOD~~)~~") for which SPP staff will issue a Notification to Construct ("NTC") **after January 1, 2015**.

Competitive Upgrades are those upgrades as defined in Section I.1 of Attachment Y of the Tariff or an upgrade for which SPP must select a replacement Transmission Owner pursuant to Section IV.3 of Attachment Y of the Tariff.

Overview of Supporting Documents

Below is a list of documents that impact the RFP process and should be considered when reviewing or responding to an RFP. See each item for a brief description:

a. Tariff – Refers to the SPP Tariff, specifically Attachment Y, which directly impacts the RFP process. If a conflict between any documents ever exist, standard to SPP practice, the Tariff shall rule.
b. Business Practices ("BPs") – This BP 7700, as well as BP 7060, have direct impacts on the RFP process.
    i. BP 7700 is to provide more guidance and clarification for the RFP process outlined in Attachment Y of the Tariff.
    ii. BP 7060 contains information regarding the NTC, Project Cost Estimating and Project Tracking processes outlined in Attachment O of the Tariff.
c. RFP Template – Otherwise referred to as an RFP, this document will be issued by SPP and will include a description of the Competitive Upgrade sufficient for the development of the RFP Proposal response by an RFP Respondent, including any ~~Transmission Owner~~ information necessary for coordination of the transmission facilities. ~~of the interconnecting Transmission Owner(s) and future designated Transmission Owners.~~ It is one of three documents that the RFP Respondent will utilize to complete the RFP Proposal response. (The other documents are the RFP Response Form and the RFP Instruction Document, detailed below.)

Comment [k1]:

Comment [k2]:

Comment [k3]: Delete Transmission Owner and verbiage added by BPWG

Comment [k4]: BPWG 2/9/2015

d. RFP Response Form – This is an Excel template that SPP has created for use by an RFP Respondent to complete and submit along with any supporting documentation to serve as an official RFP Proposal response.

e. RFP Instruction Document – This document is for use by an RFP Respondent to aide in completing an RFP Proposal response. It provides further definitions, examples, and instructions on how to complete an acceptable RFP Proposal response. It is intended purely for informational use by an RFP Respondent.

f. Minimum Transmission Design Standards ("MTDS") – This document was created through the Stakeholder process for use by an RFP Respondent when completing an RFP Proposal response. It is intended to serve as the minimum guidelines that a RFP Proposal response must meet when responding to an RFP. If a particular RFP states a value different than that shown in the MTDS, the RFP shall govern what the RFP Respondent shall use in its RFP Proposal response. If there is a conflict between an RFP and the SPP Tariff or Business Practices, the SPP Tariff shall govern.

Comment [AS5]: Provide link

g. Regional Standards *(where are they located)* – Each transmission region within SPP has varying standards that are required of projects in their zone pertinent to the different conditions and quality levels that are required to be met. If a particular RFP states a value different than that shown in the regional standards, the RFP shall govern what the RFP Respondent shall use in its RFP Proposal response. In the event a conflict exists between the regional standards and MTDS, an RFP Respondent is required to comply with the stricter design standards.

Comment [k6]: G to go back to CTPTF. BPWG 2/9/2015

h. SPP Criteria and other Governing Documents – This link provides a full list of the SPP Governing Documents. Specifically, the SPP Criteria was developed to supplement NERC documents where more detail was required to meet specific needs of SPP. This Criteria is considered as the policies, standards or principles of conduct by which the coordinated planning and operation of the interconnected electric system is achieved.

i. Integrated Transmission Planning ("ITP") Documents and Reports – This links to the SPP Transmission Planning page where copies of the ITP scopes and reports can be found.

j. Competitive Upgrade Transmission Report – This report will be issued by SPP no later than seven calendar days after the approval of projects by the BOD. The report shall include the identification of any Competitive Upgrades, the Latest RFP Issue Date, dates of the RFP Response Window (as defined in Section III.2(c)(ii) of Attachment Y), and an indication whether any DPPs are associated with the Competitive Upgrade.

Comment [k7]: The report will also include an indication of why projects that meet the competitive bidding timeline, but will not be subject to an RFP (State ROFR or other requirements).

RFP Proposal Responses

Comment [k8]: Language issue: Pizza Pizza

RFP Proposal responses may be sponsored by one or more entities. If an RFP Proposal response involves more than one sponsoring entity, at least one of the sponsoring entities must be a QRP. RFP Proposal responses with more than one sponsoring entity shall comply with all of the requirements set for in Section III.2(a) of Attachment Y that are applicable to such entity (whether an RFP Respondent or a Competitive Upgrade Participant, as defined in Section II of Attachment Y).

Comment [k9]: Term not defined in document yet.

Comment [k10]: MCN proposes to strike entire section.

RFP Issuance Process and Timeline

The process and timeline for RFPs is specified in Section III.2.d of Attachment Y of the Tariff. SPP staff will issue the RFP by or before the later of (1) seven (7) calendar days after approval of the Competitive Upgrade by the SPP BOD; or (2) 18 months prior to the date that anticipated financial expenditure is needed for the Competitive Upgrade. Anticipated financial expenditure date will be developed by ~~Staff~~SPP staff during the portfolio development stage and will be communicated in the ~~final ITP report~~. Competitive Upgrade Transmission Report ~~(to be detailed in BPR 066) that is submitted to the SPP BOD for approval~~.

Comment [k11]: Per B.Bright 2/9/2015

RFPs are only issued to Qualified RFP Participants ~~(~~("QRPs~~)~~") through email distribution. Email distribution will be made to the primary contacts included by the QRP during their application process. It is the QRPs responsibility to update SPP ~~Staff~~through the Request Management System ("RMS") of any changes to the primary contact or their contact information. ~~SPP staff will also make a list~~report ~~publicly available of all projects that are expected to be competitively bid.~~

Comment [BB12]: Competitive Transmission Project Report to be detailed in BPR 066 and added to the Bus Prac 7700

QRPs will have 180 days (the "RFP Response Window"), unless the SPP ~~Staff~~staff uses its discretion to reduce the response time window to no less than 90 days based on collaboration with stakeholders to submit their RFP ~~proposal~~ Proposal response via the ~~Request Management System (RMS).~~RMS. The RFP Response Window duration will be stated in the RFP. The estimate provided in an RFP Proposal response establishes the RFP Response Estimate~~,~~ ("RRE"), as defined in Business Practice 7060. Refer to Business Practice 7060 for more detail on SPP's required structure and accuracy of cost estimates. The information required for an RFP ~~proposal~~Proposal response is included in the RFP Response Form ~~found in Exhibit A~~. This form must be used when submitting the RFP ~~proposal~~Proposal response to SPP staff.

RFP Issuance Determination

RFPs will be issued for Competitive Upgrades based on the following determining factors:

- A single RFP will be issued for one or more new facilities and/or new lines which are dependent on each other to address a specific need or set of needs;
- Multiple RFPs will be issued for one or more new facilities and/or new lines which are independent of each other to address a specific need or set of needs, including projects within multiple state jurisdictions;

- Where issuance of an RFP would also require access or connection to an owned facility, the RFP will include language requiring the DTO ~~QRP awarded the RFP~~ to negotiate with the owner of the facility to determine connectivity or any facility work required to construct the Competitive Upgrade ~~complete the RFP; and~~.
- ~~Any RFP issuance will take into consideration individual state right of first refusal (ROFR) laws.~~

RFP Timeline to Include:

- RFP Issued Date – Date RFP is issued by SPP (RFP Response Window begins from this date)
- Pre-response ~~Conference Call~~Meeting* – Informational question and answer call regarding the RFP
- Notice of Intent to Submit RFP Proposal Response** – Non-binding notice provided to SPP by RFP Respondent(s)
  ~~Notice of Intent to Submit RFP Proposal Response** – Non-binding notice provided to SPP by RFP Respondent(s)~~
- Proposal/Deposit Deadline – All RFP Proposal response information and deposits are to be submitted by a specific date and time, which will be included in the RFP.

*The pre-response conference call is an open call to allow potential RFP Respondents to ask questions and receive feedback prior to submitting an RFP Proposal response. The Q&A will be publicly posted to SPP.org.
**The Notice of Intent to Submit RFP Proposal Response is to allow SPP informational notice to assist in managing the process.

RFP Receipt and Response

Upon receipt of an RFP ~~proposal~~Proposal response and deposit, SPP staff shall have up to ~~at least~~ 10 business days to review the proposal for completeness, and notify the RFP ~~respondent~~Respondent if its proposal is incomplete via RMS. For the purpose of this process "complete" shall mean all required information is provided. The RFP ~~respondent~~Respondent may submit information in order to complete the proposal if such submittal is made within the RFP Response Window. Any RFP ~~respondent~~Respondent that fails to submit a complete proposal within the RFP Response Window will be deemed to have waived its right to respond to the RFP. Should any submittal be deemed incomplete and it is not made complete prior to the end of the RFP Response Window, any deposit received with that submittal will be refunded in accordance with Section III of the Tariff.

RFP ~~TOSP Deposit~~Deposits and Cost ~~Calculation~~ Calculations

Comment [k13]: BPWG 2/9/2015

Comment [k14]: BPWG 2/9/2015

Comment [k15]: BPWG 2/9/2015 Check tariff language and CTPTF intent

Comment [k16]: Upon receipt of an RFP Proposal response and deposit, SPP staff shall have up to 10 business days to review the proposal for completeness, and notify the RFP Respondent if its proposal is incomplete via RMS.

Comment [BB17]: Removed this and moved to Deposit Refund Section below

The TOSP deposit and cost calculation (true-up) are outlined in Section III.2.e of Attachment Y of the Tariff. The TOSP Deposit is required with each RFP ~~proposal~~Proposal response, and is required to be paid by electronic funds transfer or by check. SPP will hold each RFP ~~respondent's~~Respondent's TOSP deposit in a segregated interest-bearing account in the name of the RFP ~~respondent~~Respondent tied to the RFP ~~respondent's~~Respondent's Internal Revenue Service Tax Identification Number. At the completion of the TOSP, SPP will determine the actual costs to administer the TOSP (detailed in Section III.2.e.ii) and each RFP ~~respondent~~Respondent will make additional payments or obtain refunds based on the reconciliation of the TOSP deposits collected and actual TOSP costs. The cost will be allocated to each RFP ~~proposal~~Proposal response on a pro-rata share basis, calculated by taking the total TOSP costs for each Competitive Upgrade and dividing by the number of RFP ~~proposals~~Proposals submitted for that Competitive Upgrade. Any unused deposit amounts will be refunded with interest earned on such deposits.

Components of the true-up cost calculation include; the TOSP deposit (revenue), Industry Expert Panel costs (retainer costs, training costs, hourly rate costs, and expenses for travel and meetings and other costs associated the panels completion of their assigned work), TOSP development costs ($2,000 per bid until the costs of developing the TOSP are recovered) and any SPP administrative work that is completed in administering the RFP.

Figure 1 shows a sample calculation; assuming a $25 million competitive transmission project where a total of 20 bids are submitted. The sample scenario also assumes a 10 person industry expert pool, 1 competitive project using a 5 member industry expert panel where each member bills a total of 10 hours per RFP response at a rate of $200 per hour. In the example the net result show expenses greater than total deposits and requires each bidder to submit additional payment to cover the total costs of the TOSP for this project.

Figure 1: Sample TOSP deposit and true-up cost calculation

Assumptions		Revenue	
IEP Pool Members	10	TOSP Deposits	$200,000
IEP Monthly Retainer Amount	$1,000		
IEP Training Payment	$4,000	**Expenses**	
IEP Panels	1	IEP Fixed Costs	$160,000
IEP Panel Members	5	IEP Hourly Costs	$200,000
IEP Hourly Rate	$200	IEP Expenses	$30,000
Competive Projects	1	TOSP Develepment Costs	$40,000
TOSP Deposit Amount per bid	$10,000	SPP Admin Costs	$50,000
Number of RFP Bids	20	Total Expenses	$480,000
Hours per bid	10		
TOSP Development cost per bic	$2,000	**Net Amount**	($280,000)
		Allocation to Bidders	($14,000)

TOSP Deposit Refunds

Only in the following occurrences will any of the RFP deposits be refunded:

1. Incomplete Responses - If SPP staff determines that an RFP Proposal response was not 'complete' prior to the end of the RFP Response Window and thus will not be considered in the project assessment then the TOSP deposit will be refunded as described in Section III of Attachment Y of the Tariff. These bids will not be subject to the true-up cost calculation.
2. RFP Withdrawal – If the SPP BOD withdraws an RFP due to all bid cost estimates exceeding the cost estimates provided by SPP at the time the project was approved for construction then the TOSP deposit will be refunded as described in Section III of Attachment Y of the Tariff. These bids will not be subject to the true-up cost calculation.

Comment [BB18]: Should any submittal be deemed incomplete and it is not made complete prior to the end of the RFP Response Window, any deposit received with that submittal will be refunded in accordance with Section III of the Tariff.

Confidential Information

All information received in an RFP Proposal response will be considered confidential by SPP except for information used to create an NTC for the Selected RFP Proposal, as described in SPP Business Practice 7060.

For information related to the Industry Expert Panel ("IEP") reports, all reports will be handled according to rules established in Attachment Y Section III.2.d.vi of the Tariff. The Selected RFP Proposal for each Competitive Upgrade, as selected by the BOD, will be subject to further release of information, but not to include information the RFP Respondent identifies as confidential.

Annual Transmission Revenue Rights ("ATRR") Template

If a RFP Respondent has a FERC accepted Formula Rate then that RFP Respondent shall use it when responding to an RFP for the purposes of meeting requirements in Att. Y Section III.2.f.4. If a RFP Respondent does not have a FERC accepted Formula Rate (or is not in the process of developing one that could be reviewed for contents by SPP staff) then the respondent shall complete the SPP provided ATRR Template along with all supporting documentation to detail any and all assumptions made by the RFP Respondent in the calculations.

Steps to complete this RFP Proposal Response Requirement:

Decision: If RFP Respondent has Formula Rate, provide all cost items specific to the RFP Proposal response within their existing Formula Rate Template. Do not proceed to next decision point.

Decision: If RFP Respondent does not have a Formula Rate, follow the process below:

Step 1: Complete 40 year NPV calculation for the project (Tab 6 of RFP Response Form titled, "ATRR Template")

Step 2: Complete and provide all supporting documentation to detail any and all assumptions made in the calculation of Net Plant Carrying Charge ("NPCC") by the RFP Respondent. Assumptions detailed should include at a minimal the following list:

1. Depreciation
2. Carrying Charge (Return on Rate Base)
3. Operation & Maintenance ("O&M")
4. A&G (Overhead allocation)
5. Income Tax Rate
    a. State
    b. Fed
6. Property Tax
7. Taxable Component
8. Revenue Credits for Point-to-Point shall be factored in the calculations

Comment [AS19]: Update Tab number accordingly

Comment [k20]: Perhaps a better term

Comment [k21]: FCR?

Notification of DPPs in Approved Final ITP or High Priority Portfolio

The ~~SPP Board of Directors~~BOD will approve the final ITP or High Priority portfolio of projects and SPP ~~Staff will update the final ITP report to place an asterisk ("*") next to any projects that~~ staff will include which Competitive Upgrades have associated DPP(s~~). ~~)~~ in the Competitive Upgrade Transmission Report.

RFP Notification to Construct (NTC)

The ~~final selected~~Selected RFP Proposal will be issued an NTC pursuant to Section V of Attachment Y of the Tariff.

For more information, send any questions via SPP RMS or contact SPP Customer Relations.

2014 Capacity Margin LOLE Study

February 18, 2015

SPP Engineering

SPP Southwest Power Pool

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

Overview

- Background
- Objectives
- Study Inputs and Assumptions
- Data Description
- Study Results
- Recommendation

Background

- SPP Criteria 4.3.5 states “SPP will use a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments will be performed by the SPP on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria (2.0) requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10% - 11% capacity margin.”
- The Capacity Margin Loss of Load Expectation (LOLE) study investigates the expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand

Objectives

- **The Capacity Margin LOLE study provides an assessment of whether currently installed capacity is adequate to serve the forecasted load, given a set of random generator outages and load uncertainty factors, and determine if the capacity margin requirement of 12% is adequate to maintain an LOLE of 1 day in 10 years.**

Study Inputs and Assumptions

Category (SPP Region)	2016 Study (MW)	2018 Study (MW)
On-Peak Expected Demand	54,242	55,760
Demand-Side Management-Available	1,137	1,340
On-Peak Expected Capacity (Coal)	25,320	25,530
On-Peak Expected Capacity (Gas)	30,461	30,720
On-Peak Expected Capacity (Hydro)	5,224	5,224
On-Peak Expected Capacity (Nuclear)	2,420	2,420
On-Peak Expected Capacity (Wind)	577	577
On-Peak Expected Capacity (Solar)	5	5
On-Peak Expected Capacity (Oil, Biomass, Other)	2,228	2,228
Firm Sales	3,522	3,522
Firm Purchases	3,040	3,040
Total Capacity	66,890	66,988

Data Description

- **Areas**
  - 17 Study areas based on SPP Planning Coordinator Region (including the Integrated System)
  - Includes all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, New Mexico, Montana, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas
  - Integrated System includes Eastern Interconnect portions of Western Area Power Administration, Basin Electric Power Cooperative, Heartland Consumer Power District, Northwestern Energy, Missouri River Energy Services, and Corn Belt Power Cooperative
- **Base Models and Topology**
  - 2015 series ITPNT summer peak models years 2016 and 2018
- **Hourly Load Profiles and Peak Loads**
  - Member submitted data through the EIA-411 form for Non-coincident annual peak loads and energy
  - Load profiles created from historical hourly load data from 2007 to 2011 for each area

Data Description (Cont.)

- **Dispatchable Capacity and Generation**
  - Generation Capacity, Forced Outage Rate, Outage Duration, Fuel Price, Maintenance schedules, and Jointly Owned Resource
  - Data sourced from current PROMOD data, EIA-411 data, or member submitted data
  - 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 thermal generation
- **Wind**
  - Approximately 10.5 GW of nameplate capacity for 2016 and 11.5 GW for 2018
  - Submitted data was used and calculated by SPP Criteria 12.1.5.3 section G. If not submitted, data was obtained through National Renewable Energy Laboratory (NREL) and given 5% capacity accreditation
  - Hourly wind generation is based upon averaged historical profiles from 2007 to 2011

Data Description (Cont.)

- **Constraints and Monitored Elements**

Elements	2016 Study	2018 Study
Contingencies	183	183
Monitored Branches (230 kV and above)	1049	1346
Tie-lines from SPP to an external region	13	13
Total branches in Tie-lines	410	410

  - Data obtained through SPP Operation's OASIS flowgate list and the SPP PSS/E power flow model

- **DC Ties**
  - Modeled as hourly generators at the point of interconnection to SPP
  - Hourly load shapes based on a historical average of 5 years (2007 to 2011) provided by SPP Operations department

- **Demand Response**
  - Equivalent thermal units were added to the model with high fuel costs, so those units would be dispatched last to reflect demand-response operating scenarios

Data Description (Cont.)

- **Capacity Sales and Purchases**
  - Firm Transactions from EIA-411 member submissions
  - Modeled as generator on swing bus for each area
  - All transactions were balanced between areas that were intra-area to SPP
  - All inter-area transactions were accredited on the area's swing bus with a different generator
- **Monte Carlo Simulation**
  - conducted simulations at 2400 trials
  - The maximum number of outages per hour was set to 10 resources and the maximum number of new outages per hour was set to 5 resources.
  - Each trial represents a single 8760-hour simulation

Study Results

MRA metrics results		
SPP Region	2016	2018
EIA-411 Forecast Planning Capacity Margin (%)	18.9%	16.7%
SPP Criteria Target Capacity Margin (%)	12.0%	12.0%
LOLE set to target Capacity Margin (days/year)	0.0	0.00083**
LOLE SPP Criteria Requirement (days/year)	0.1	0.1

- The Loss of Load Expectation (LOLE) Per the SPP Criteria and industry standard is one day in 10 years (0.1 day/year). Daily LOLE is the expected daily occurrences of the loss of load throughout the year
- **The results for the 2018 study reflects the area deficient in meeting the 12.0% capacity margin requirement for 2018 in the submitted EIA-411 form. This number also represents the statistical probability of an event occurring over 2400 trials.

Recommendation

- **SPP Staff recommends ESWG endorse the 2014 Capacity Margin LOLE Report as documentation of completion of the 2014 Capacity Margin LOLE study as specified in SPP Criteria section 4.3.5**

2014 Capacity Margin LOLE Report

2/11/2015

SPP Engineering

SPP Southwest Power Pool

Revision History

Date or Version Number	Author	Change Description	Comments
12/31/2014	Alex Crawford	Initial Release	
1/2/2015	SPP Staff	Reviewed and Modified	
2/11/2015	SPP Staff	Reviewed and Modified	

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Introduction

SPP Criteria 4.3.5 states “SPP will use a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments will be performed by the SPP on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria (2.0) requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10% - 11% capacity margin.”

The Capacity Margin Loss of Load Expectation (LOLE) study investigates the expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand. The LOLE is usually measured in days/year or hours/year. The convention is that when given in days/year, it represents a comparison between daily peak values and installed capacity. LOLE is sometimes referred to as loss of load probability (LOLP), where LOLP is the proportion (probability) of days per year, hours per year, or events per season that installed generating capacity/energy is insufficient to serve the daily peak or hourly demand. This analysis is generally performed for several years into the future and the typical industry standard metric is the loss of load probability of one day in ten years or 0.1 day/year. LOLE is a DC power flow study, so it does not address voltage or stability issues.

Objective

The LOLE study provides an assessment of whether currently installed capacity is adequate to serve the forecasted load, given a set of random generator outages, and determine if the capacity margin requirement of 12% is adequate to maintain an LOLE of 1 day in 10 years.

Study Assumptions

Category (SPP Region)	2016 Study (MW)	2018 Study (MW)
On-Peak Expected Demand	54,242	55,760
Demand-Side Management-Available	1,137	1,340
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On-Peak Expected Capacity (Gas)	30,461	30,720
On-Peak Expected Capacity (Hydro)	5,224	5,224
On-Peak Expected Capacity (Nuclear)	2,420	2,420
On-Peak Expected Capacity (Wind)	540	575
On-Peak Expected Capacity (Solar)	5	5
On-Peak Expected Capacity (Oil, Biomass, Other)	2,228	2,228
Sales[1]	3,522	3,522
Purchases	3,040	3,040
Total Capacity[2]	65,716	65,770

[1] All capacity sales and purchases are cumulative totals of firm import or export transactions with respect to the entire SPP region.
[2] The total capacity calculations do include the available demand-side management totals.

Data Description and Analysis

GridView is the modeling tool used for the Capacity Margin LOLE analysis. Production-cost models such as GridView require many different and detailed data inputs. The information below details what data was used to build and simulate the models used in the Capacity Margin LOLE study.

Areas

The SPP Planning Coordinator footprint includes all or parts of Arkansas, Kansas, Louisiana, Missouri, New Mexico, Nebraska, Oklahoma, and Texas. Based on member input Iowa, Minnesota, Montana, North Dakota, and South Dakota have been included based on possible integration of Western Area Power Administration, Basin Electric Power Cooperative, Heartland Consumer Power District, NorthWestern Energy, Missouri River Energy Services, and Corn Belt Power Cooperative. For simplicity these entities have been listed as WAPA in the list below. The areas used in the in the 2014 study include the following:

AEPW[3,4]	American Electric Power West
EMDE	Empire District Electric Company
GRDA	Grand River Dam Authority
INDN	Independence Power & Light Department
KACY (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[5]	Southwestern Power Administration
WAPA[6]	Western Area Power Administration
WERE[7]	Westar Energy, Incorporated
WFEC	Western Farmers Electric Cooperative

[3] FERC 714 Hourly Load data for AECC is reported through AEPW, OKGE, and SWPA.
[4] FERC 714 Hourly Load data for OMPA is reported through AEPW, OKGE, and WFEC.
[5] FERC 714 Hourly Load data for SPRM is reported in SWPA through 2010. 2011 SPRM Hourly Load data was added to SWPA numbers to create the forecasted hourly load shape.
[6] WAPA contains eastern interconnect portions of Western Area Power Administration, Basin Electric Power Cooperative, Heartland Consumers Power District, NorthWestern Energy, Missouri River Energy Services, and Corn Belt Power Cooperative.
[7] FERC 714 Hourly Load data for MIDW is reported through WERE.

Base Models and Topology

System Topology was drawn from the 2015 series ITPNT summer models for the 2016 and 2018 study years. Transmission additions and retirements were captured in the ITPNT models built with SPP member input. Transmission additions were modeled and retirements were removed from the GridView models.

Hourly Load Profiles and Peak Loads

The study models use the non-coincident annual peak loads of each SPP area sourced from member submitted data through the EIA-411[8] form for each entity. Historical hourly load data from 2007 to 2011 was used to produce an 8,760 hourly load profile for each modeled Metric Reporting Area (MRA). The historical data was obtained by either member data submittals or FERC 714 filings. The data was then modified by normalizing each hour to the maximum load value for each year, shifting each year to match the correct day of the week, averaging the years together, and multiplying the normalized values by the projected peak load. These years provided a typical range of load patterns, along with being the most recent years available.

Traditional Dispatchable Capacity and Generation Modeling

Generation data included using various fields of data: Generation Capacity, Forced Outage Rate, Outage Duration, Fuel Price, Maintenance schedules, and Jointly Owned Resource information from current PROMOD data, EIA-411 data, or additional member submitted data.

Ratings

The maximum capacity ratings were based on 2014 EIA-411 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[9].

Forced outage modeling

Forced outage modeling within GridView consists of using the Equivalent Forced Outage Rate – demand (EFORd) values provided from Ventyx[10]. Values for forced outage rates, forced outage durations, and scheduled maintenance 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.

Simulation parameters for random forced outages were calculated from hourly winter season historical forced outages from December 2013 to February 2014. Based upon a yearly analysis, this time frame is typically when forced outages increase. The maximum number of outages per hour parameter was to ten resources and the maximum number of new outages per hour was set

[8] The EIA-411data for the area labeled WAPA was submitted by Mid-Continent Area Power Pool (MAPP) on behalf of the WAPA area entities. MAPP provided SPP with the most recent EIA-411 version of each entity.
[9] http://www.spp.org/publications/SPP%20Criteria%20and%20Appendices%20Jan.%202012.pdf
[10] http://www.ventyx.com/

to five resources. The analyzed data reflected the given forced outage setting for max number of outages per hour.

Planned outage modeling

Planned outages for thermal units, provided by data submissions by members, 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)[11] software SPP members use to plan maintenance outages. If generators did not have a designated outage planned, previous planned outage times were modeled from previous studies.

Behind-the-meter generation

Behind-the-meter generation is generally netted and modeled with customer load. If the behind-the-meter generation was not netted, then it was modeled as regular generation.

Wind Modeling

The model includes all wind generation currently installed (approximately 10.76 GW of nameplate capacity for 2016 and 11.47 GW for 2018). Hourly wind generation is based upon averaged historical profiles from 2007 to 2011, which were obtained through member data submittals, operations departments within SPP, or NREL (National Renewable Energy Laboratory). Wind facilities that submitted data were given the capacity accreditation based upon SPP Criteria 12.1.5.3 section G. All other wind facilities fell under SPP Criteria 12.1.5.3 section G-5-C which states "If the Load Serving Entity chooses not to perform the net capability calculations as described [in section 12.1.5.3] during the first 3 years of commercial operation, the Load Serving Entity may submit 5% for wind facilities…".

Constraints and Monitored Elements

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 between one region and 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.

[11] Maintenance schedules for Integrated System (Western Area Power Administration, Basin Electric Power Cooperative, Heartland Consumers Power District, NorthWestern Energy, Missouri River Energy Services, and Corn Belt Power Cooperative) were obtained through member submitted data.

The penalty of violating any constraint is $1,000/MWh while the load shedding penalty is $800/MWh. Therefore, the system tends to shed load before violating any transmission constraint. The number of transmission constraints varied in the 2016 and 2018 studies. Not only were specific constraints monitored, specific groups of ties between regions and every branch 230 kV and above within the SPP region were also monitored. The monitored elements need to be kept to a minimal amount in order to reduce run-time. The number for each element within both studies is listed below.

Elements	2016 Study	2018 Study
Contingencies	183	183
Monitored Branches (230 kV and above)	362	372
Tie-lines from SPP to an external region	13	13
Total branches in Tie-lines	410	410

DC Tie Modeling

DC ties were modeled as hourly generators, similar to wind, at the point of interconnection to SPP. They were given hourly load shapes which were derived from an average of historical hourly data within a 5 year time span (2007 to 2011). The hourly flow amount for each DC tie was provided by the operations department within SPP or by member submissions of historical values.[12]

Capacity Sales and Purchases

All capacity sales and purchases were firm transactions. The transactions used for both study years were obtained through the SPP ITP models and verified against the EIA-411 submissions.

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. This methodology is how GridView handles transactions.

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

[12] The DC Ties located north of Nebraska and within the WAPA balancing area were included in the LOLE study as well. The historical data for these DC Ties were provided to SPP from Western Area Power Administration.

entity, the capacity would be negative. If the transaction was a purchase, the capacity would be positive.

Demand Response Modeling

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.

Modeling Load Forecast Uncertainty

Method

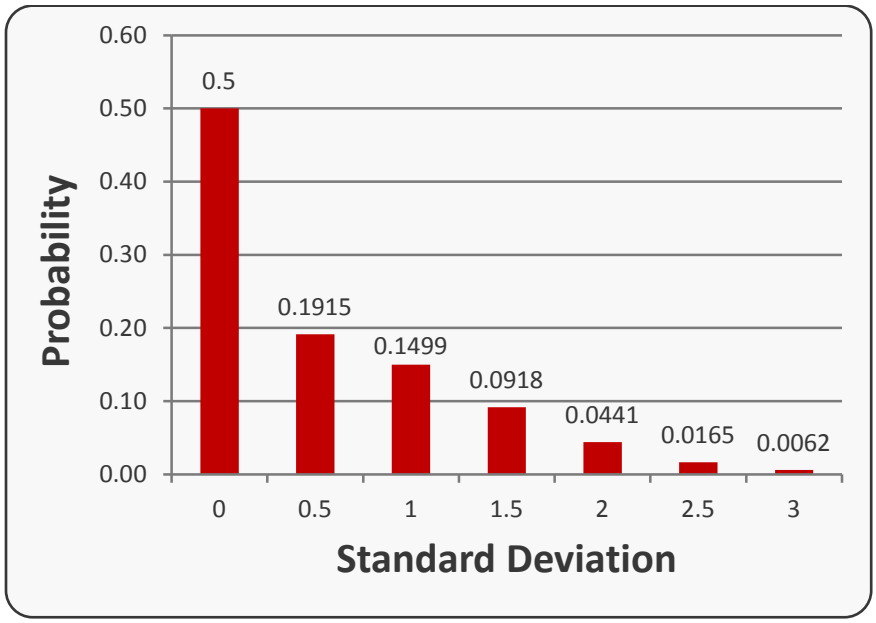
GridView allows for two options in dealing with load uncertainty: 1) User defined uncertainty pattern, and 2) probability distribution. For this study, a user-defined uncertainty pattern and a probability distribution were both used to add uncertainty to the load values. A different load uncertainty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

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 2007-2011. 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 multipliers were then normalized to where the highest multiplier was 0.5% higher than the base multiplier. All other multipliers between the base and the highest multiplier were given load increases from 0% to 0.5% based upon a linear regression in relation to the proportional increase of each multiplier. The user-defined uncertainty pattern allows users to provide seven monthly load patterns. Each area has a different value for each month multiplied by 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 random load uncertainty allows for unexpected increases of load added to the adjusted 12.0% capacity margin requirement to meet SPP Criteria 4.3.5.

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.



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.

Monte Carlo Simulation

SPP conducted the GridView Monte Carlo Simulation at 2400 trials, in which five resources in SPP may be forced out of service at the same hour of study. The trials account for variations in forced outages and wind output. Each trial represents a single 8760-hour simulation. The stop criteria for the Monte Carlo simulation is to make the standard error of LOLE less than or equal to a threshold of 0.05. GridView calculates standard error to determine whether more simulation is needed.

Results

Metric Reporting Area

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).

Study results

Capacity margin percentages were submitted for each modeled area based upon certain capacity, net firm transactions, available demand-side management, and projected peak demand values. All submissions exhibited a capacity margin above 12.0% for 2016 and 2018 except for one area in the 2018 study.[13] The non-coincident peak demand values were then adjusted for each area based upon the expected capacity. An increase in peak demand resulted in a lower capacity margin and was assigned per area for the trial simulations to reflect 12.0% capacity margin across the SPP region. Based upon the given EIA-411 values, no loss of load was shown in the SPP footprint for the 2016 study and 0.00083 days per year for the 2018 study. The values in the table below reflect the results of the GridView LOLH/LOLE simulations for both study years (2016, 2018).

[13] Even though one area was under the required capacity margin for 2018, the SPP region still met the SPP Criteria of one day in ten years.

MRA metrics results[14]

SPP Region	2016	2018
EIA-411 Forecast Planning Capacity Margin[15] (%)	19.2%	17.3%
SPP Criteria Target Capacity Margin (%)	12.0%	12.0%
LOLE (days/year) set to target Capacity Margin (2400 trials)	0.0	0.00083[16]
LOLE (days/year) SPP Criteria Requirement	0.1	0.1

[14] All results are based upon member submitted data at the time of beginning the LOLE assessment.
[15] The EIA-411 member submitted planning capacity margin included totals previously listed in the Assumptions section. The available demand-side management values were included as a load reduction for the calculation.
[16] The results for the 2018 study reflects the area deficient in meeting the 12.0% capacity margin requirement for 2018 in the submitted EIA-411 form. This number also represents the statistical probability of an event occurring over 2400 trials.

Conclusion

2016 Capacity Margin LOLE study

With the inclusion of the near-term transmission projects in the SPP region, along with the installation of new capacity and firm imports from external regions, there was no unserved load at 12.0% capacity margin, which meets the industry standard of maintaining an LOLE of 1 day in 10 years (0.1 days/year) and SPP Criteria.

2018 Capacity Margin LOLE study

With the inclusion of the near-term transmission projects in the SPP region, along with the installation of new capacity and firm imports from external regions, there was unserved load at 12.0% capacity margin of 0.00083 days per year, which meets the industry standard of maintaining an LOLE of 1 day in 10 years (0.1 days/year) and SPP Criteria.

Software model description

Computational Approach

GridView 9.1.12 was used to perform the LOLE study 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 Capacity Margin study.

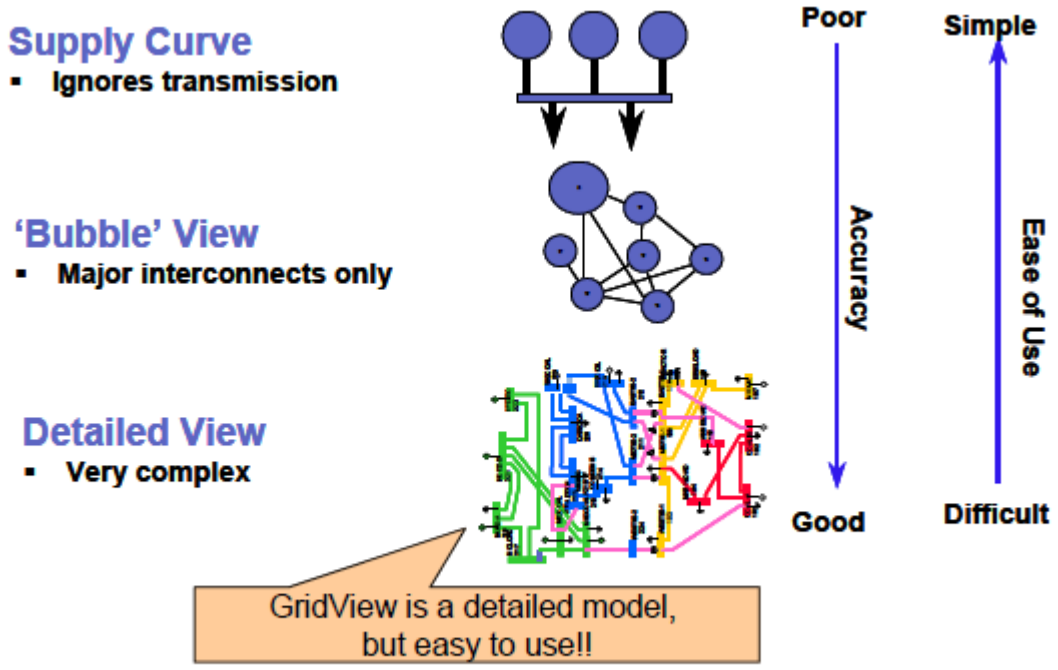


Figure 1-2 GridView Uses Very Detailed Transmission System Model

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, multiple simulations will have to be performed (2,400 simulations/year study). In general, the simulations provide the loss of load reliability indices. 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.

Tiered Simulation

The 2014 Capacity Margin LOLE study 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. The next simulation type incorporated 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. With 230kV and above being monitored, simulation time was approximately 60 hours for the 2400 trial simulation.

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.

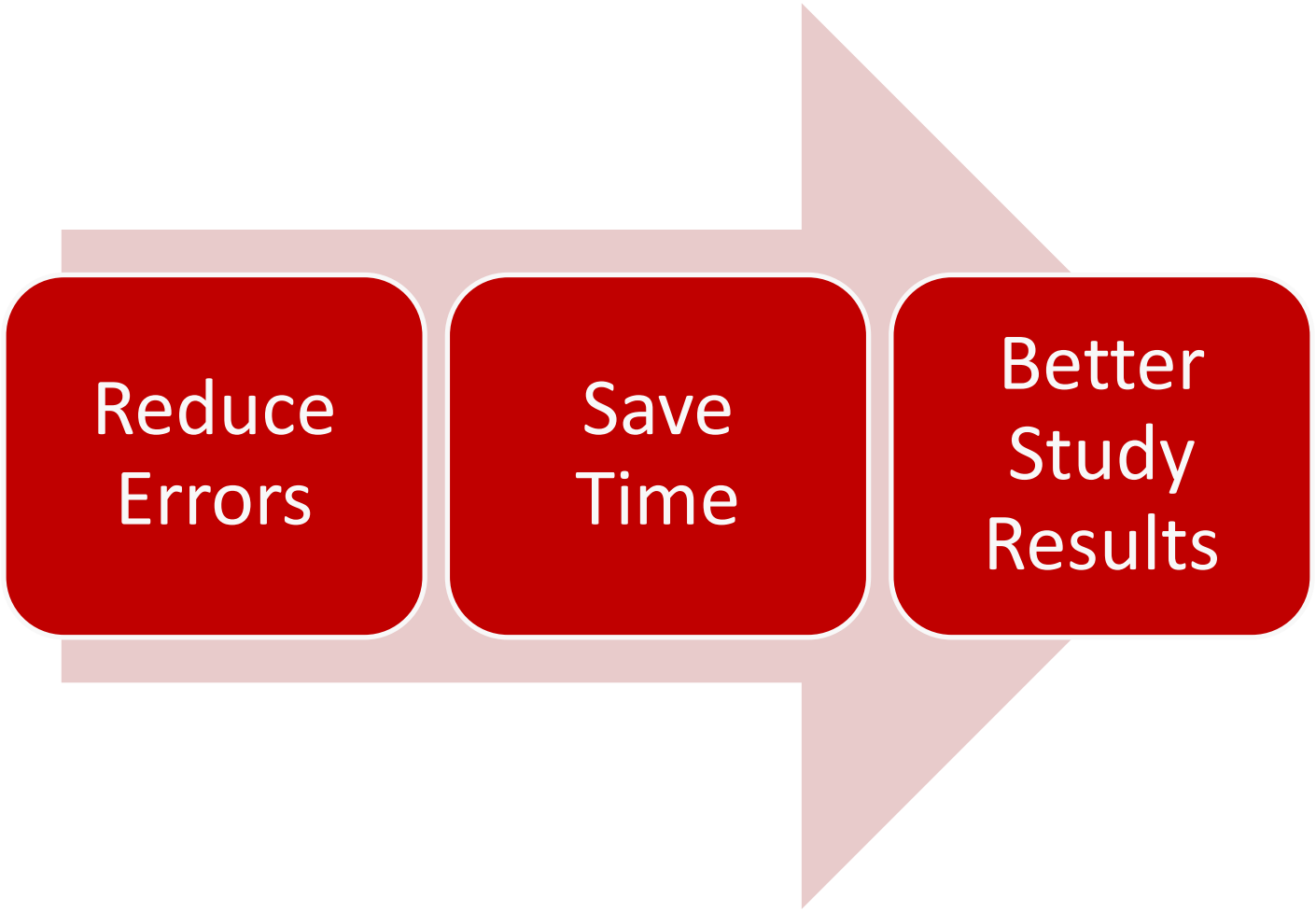
ITP Process Improvement

Amber Greb

February 18th, 2015

Southwest Power Pool

Purpose



ITP Process Improvement

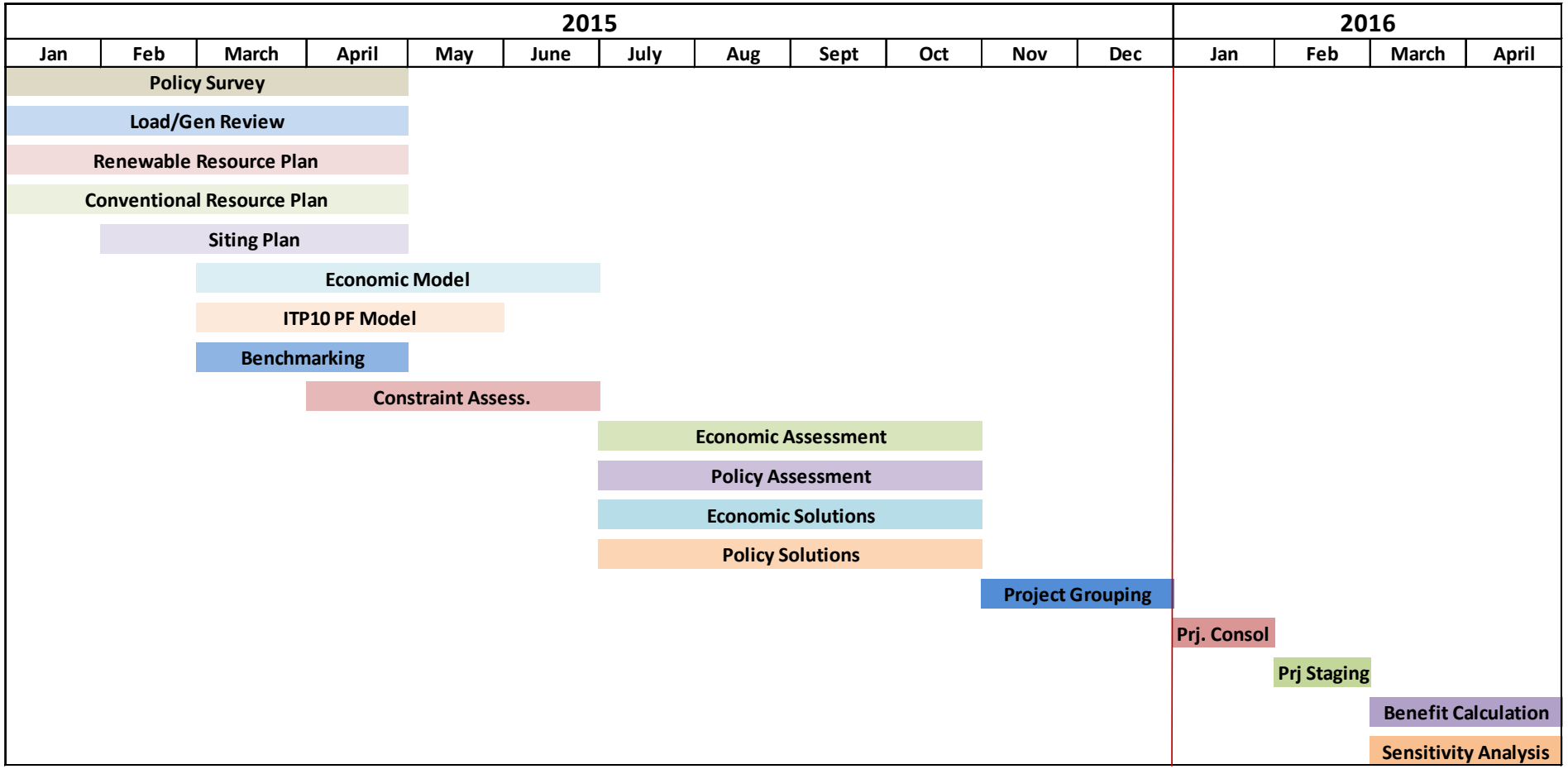
- Data Gathering
  - Simplifying\clarifying submittal forms
  - Consistency between data sets
- Looking for Automation Opportunities
  - Saves Time
  - Error Reduction
- Documentation
  - Well defined and documented processes
  - Accountability

Better Study Results

- Reduced Errors
  - More accurate results
- Time Savings
  - Allows more time to really analyze and dig into results
- Less time on the process means more time spent on what Stakeholders really care about…

Results!!

ITP Process Improvement Schedule



Driver 111D	Future 1 Regional 111D	Future 2 State 111D
• Competitive Wind		
o Sub $24 prices	Yes	Yes
• NG Supply		
o High-Supply NG Due to Fracking	Yes	Yes
o Low-Supply NG Due to Fracking Regulation		
• Severe Weather	Sensitivity	Sensitivity
o Long-Term Drought		
o Winter impacts		
• Green Future		
o 10% load reduction due to distributive generation		
o 111D passed at 100%		
o RPS		
• Technology Advancement	Next ITP20	Next ITP20
o Fusion Reactors		
o Generation Technology		
o Transmission Technology		
• DC		
• High capacity AC		
• Metering		
• Customer control		
o Controls		
• Changing Renewable Portfolio Standards		
• Cost of Capital Changes (Significant Increase)	Sensitivity	Sensitivity
o Limited ability to build		
o 8-12% interest payments		
• Solar Development (Substantial)	Large Scale	Large Scale
• Impact on Generation Due to Constraints	Modeling Issue	Modeling Iss
o Low Generation		
• Coal retirement		
• Resource adequacy issues		
• Physical Security (Hyper-Physical Security)		Consistent acr
o Military bases generating power for security reasons		
o Terrorists attacks against large substations		
• WECC Connectivity (Extensive West Connectivity)	ITP20	ITP20
• Load Growth	Normal	Normal
o Economic development causes High Load Growth		
o Continued recession causes negative Load Growth		

Future 3	Future 4	Notes
No 111D	Worst Case	We don't want worst case future to become the kitchen sink. Future 4 includes a
Yes	No PTC available, price of wind goes up	
Yes		
	Yes	
Sensitivity	Sensitivity	
		This driver is captured in 111D driver and competitive wind.
		Some thought that this might be a better place to capture wind
Next ITP20	Next ITP20	
		Captured in the 111D driver
Sensitivity	Yes?	
Mix of Large	Large Scale	F1 & F2 the same, F4 higher that F1 & F2.
Modeling Iss	Modeling Issue	
oss futures		Needs more discussion
ITP20	ITP20	
Increased	Decreased	

a high carbon tax

RCAR II Modeling Discussion

February 19th, 2015

ESWG

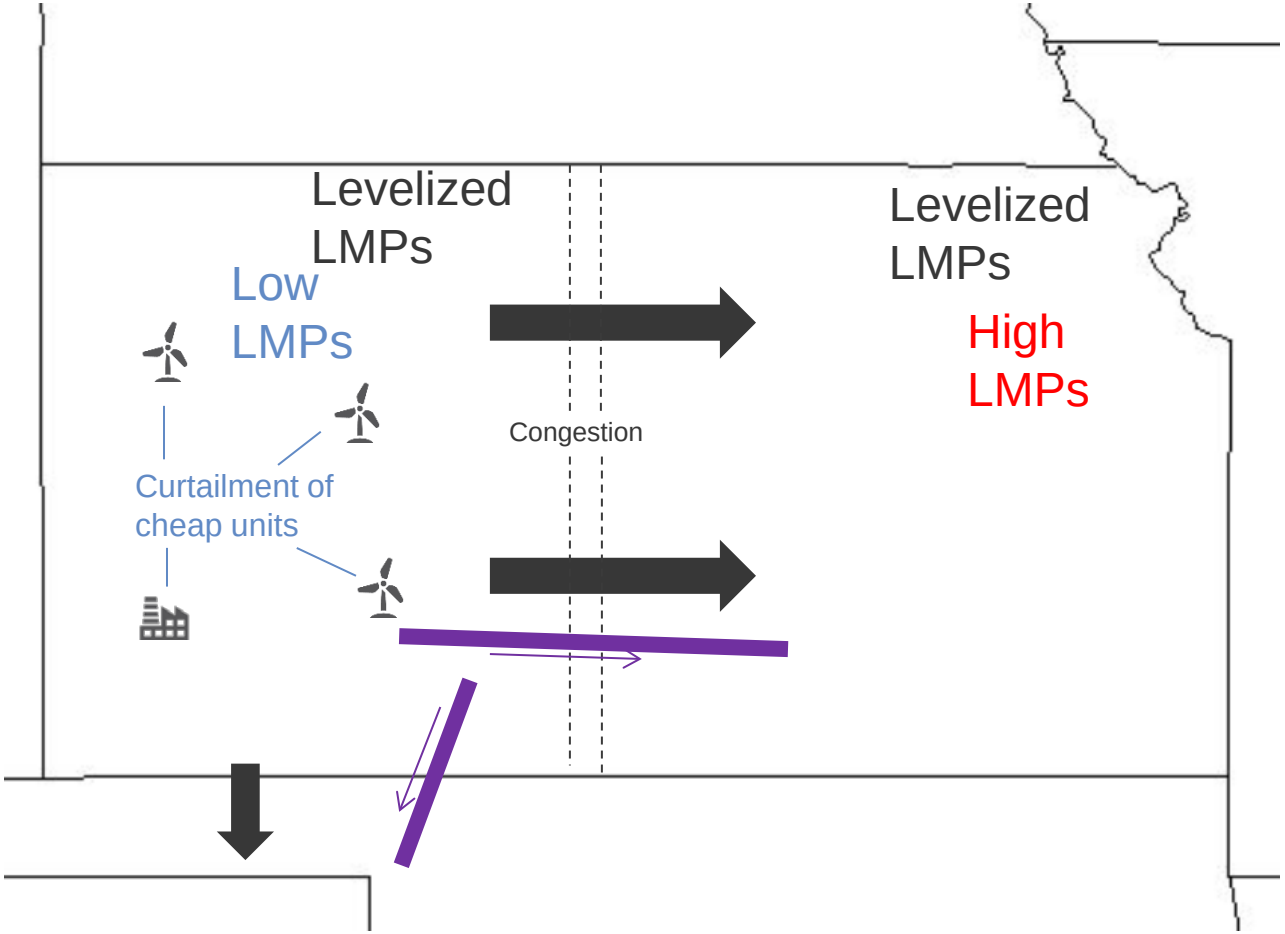
SPP Southwest Power Pool

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

Economic Modeling Issues Technical Discussion

- 1/29: Introduced the 2 issues, agreed to bring more material for discussion in future conference call
- 2/11: Discussed the issues in more depth, more data was requested
- 2/19: Continue discussion, work to finalize approaches
  - Numbers presented today are very preliminary and are subject to change due to modeling and constraint updates, refinements, etc.

Issue #1: Trapped Generation Pockets



Base Case

Lack of transmission ->
Curtailment of cheap units ->
Large LMP differential ->
Low LMP purchase prices in west KS ->
Low APC

Change Case

Robust transmission ->
Cheap units generate more->
Levelized LMPs ->
Moderate LMP purchase prices in west KS ->
Moderate APC

Under current approach:

- APC savings is negative for west KS zones, even though the new transmission unleashes more of their cheap generation.
- Conversely, APC savings for zones to the east will be inflated due to artificially high LMPs in the base case

Load and gen are identical between base and change cases

Issue #1: Trapped Generation Pockets

- West KS zones are showing negative APC savings, even though their more expensive generation is being displaced with cheaper generation in the change case
  - This issue is created due to the modeling approach adopted in the RCAR process
  - When the economic models are transmission-deficient, current modeling practices overstate the separation of prices between zones
    - Impact more pronounced in smaller zones
  - Model does not recognize that wind interconnection was granted subject to transmission upgrades

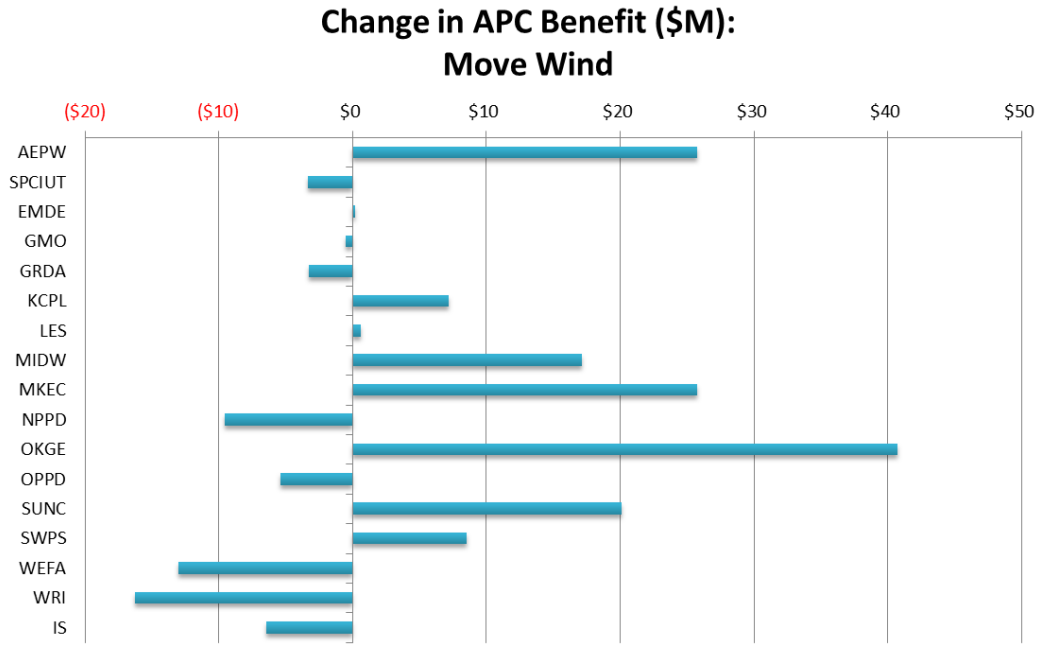
Issue #1: Solutions

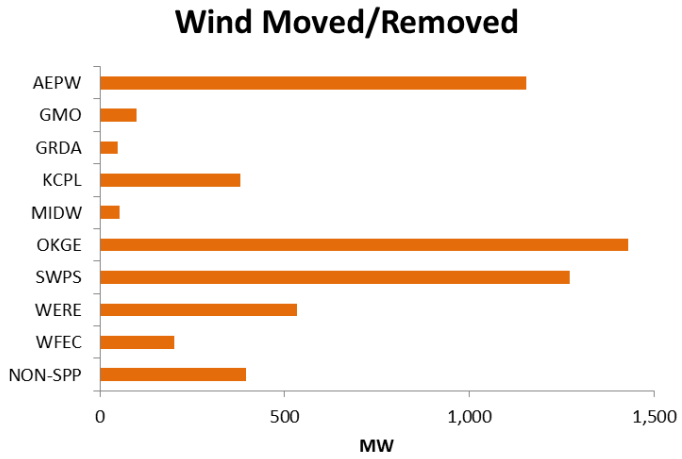
- Option 1a: Status Quo
- Option 1b: Move Wind to Zonal Load Centers
- Option 1c: Remove Wind
- Option 1d: Hybrid Approach
- Option 1e: Incremental Approach
  - No results for this approach

- All results are 1-year APC savings, 2034 $

Option 1b: Move Wind to Zonal Load Centers

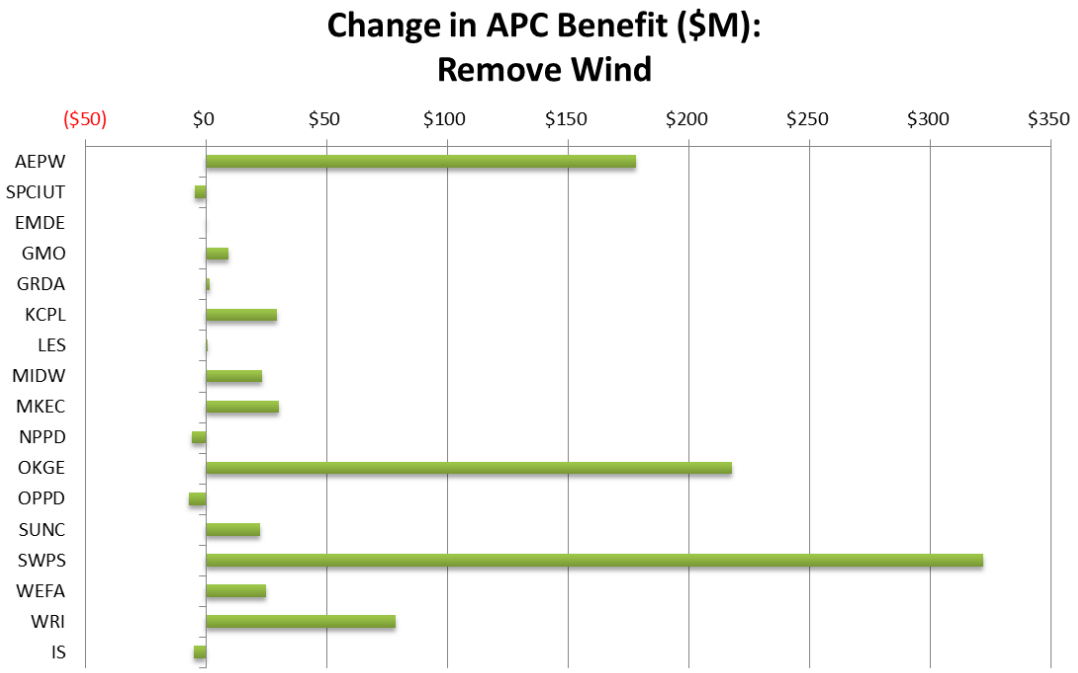
- Move wind only if it is dependent on the HWBW transmission (5.0 GW)
- Decreases capacity factors
- Zones would still need to meet their public policy mandates/goals

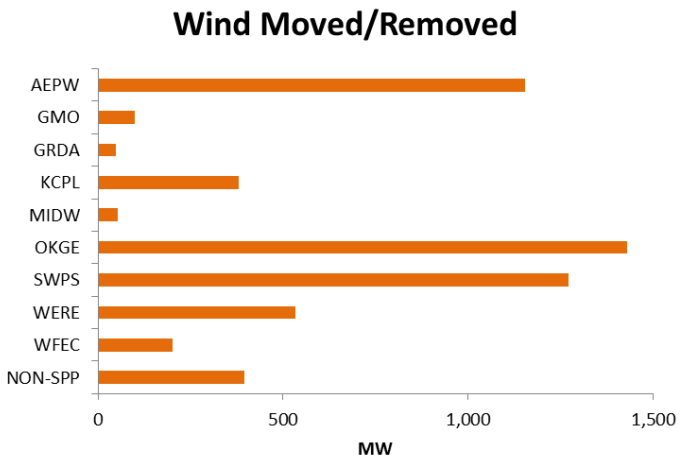




Option 1c: Remove Wind

- Remove wind only if it is dependent on the HWBW transmission (5.0 GW)
- These numbers do not account for capital cost of wind



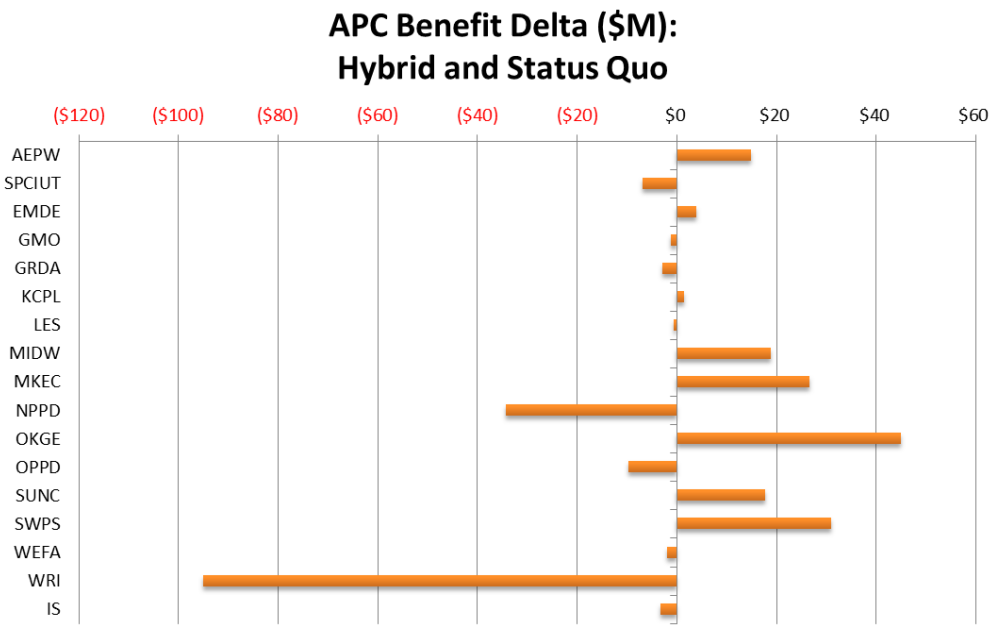


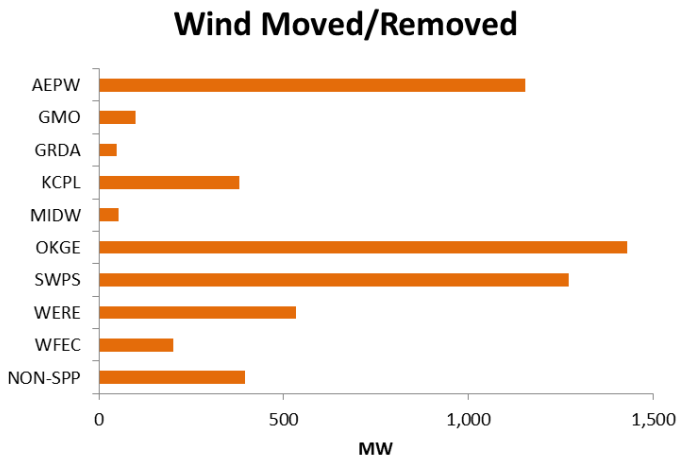
Option 1d: Hybrid Approach

- Approach 1 (A1): Status Quo, wind in both base and change cases
  - Good for analyzing regional benefit
  - Problematic for analyzing zonal benefits
- Approach 2 (A2): Remove Wind, wind is taken out of base case
  - Problematic for analyzing regional benefit
  - Good for analyzing zonal benefits, as % share of regional benefits
- Calculate X by zone as the APC benefit:

$$\frac{\text{Zonal APC Benefit}_{A2}}{\text{Regional APC Benefit}_{A2}} = \frac{X}{\text{Regional APC Benefit}_{A1}}$$

Option 1d: Hybrid Approach



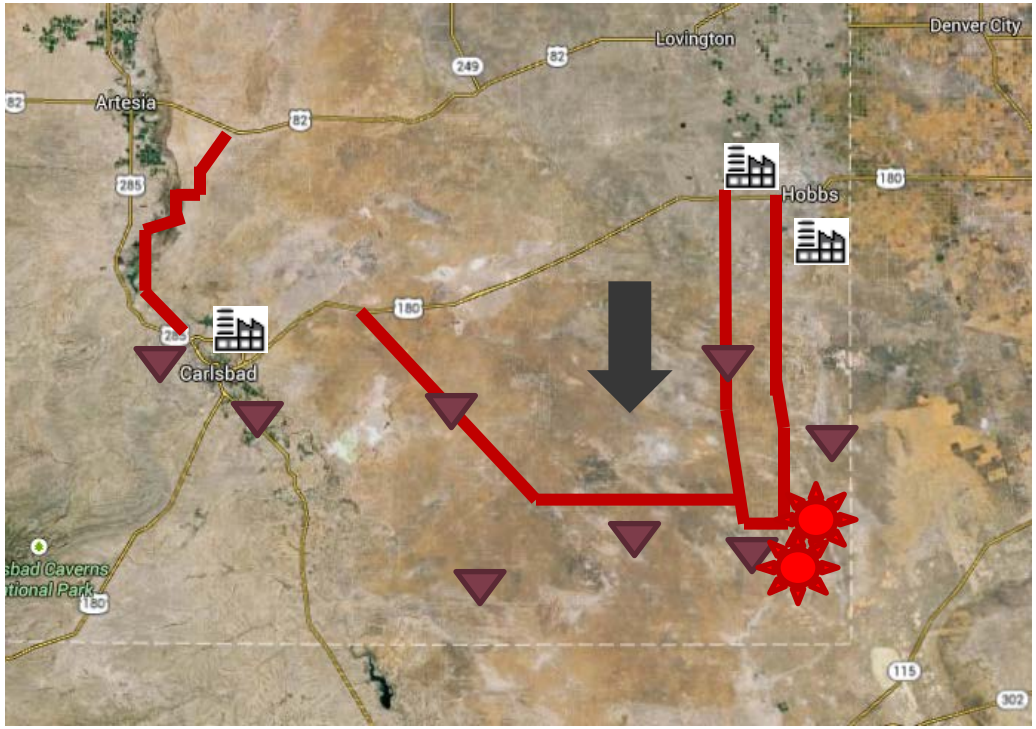


Option 1e: Incremental Approach

- Identify the specific projects creating the bulk of the problem with wind (wind projects)
  - Base B1: Include the wind projects, no other HWBW
  - Change C1: Include all HWBW
  - Change C2: Include all HWBW except for the wind projects
- APC Benefit 1 = B1 – C1
- APC Benefit 2 = C2 – C1
- Total APC Benefit = APC Benefit 1 + APC Benefit 2
- Incremental approach avoids the LMP differentials that occur in the original base case

Issue #2: Load Pockets

- Load pocket does not have enough transmission to serve load in base case
- Excessive emergency gen and breaching constraints are causing high LMPs in the base case, resulting in high APC

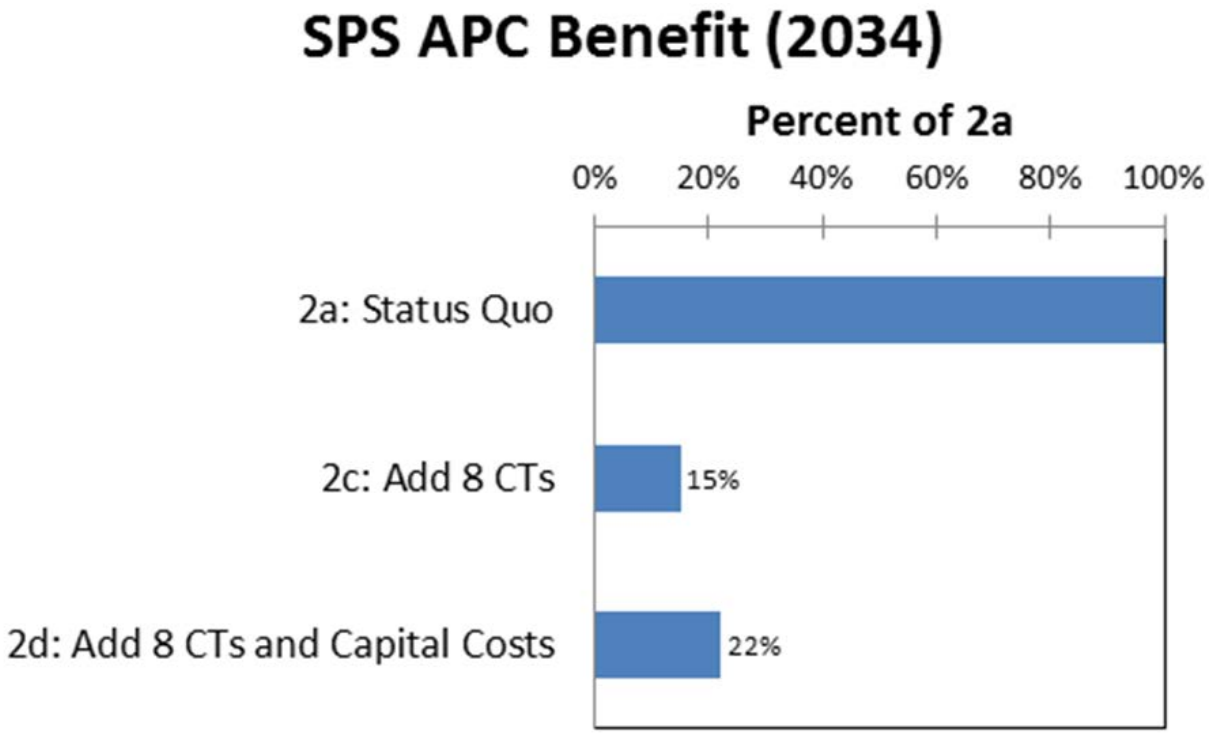


Issue #2: Solutions

- Option 2a: Status Quo
- Option 2b: Add load pocket upgrades to base case
  - No results at this time
- Option 2c: Add CTs in base/change case, make non-dispatchable in change case
  - Added 8 CTs, 1,680 MW
- Option 2d: Add CTs in base/change case, make non-dispatchable in change case, include CT capital costs
  - Added 8 CTs, 1,680 MW

Issue #2: Solutions

- Options 2c and 2d effectively address the emergency generation and breaching constraint problems



2017 ITP10 Study Methodology

SPP Staff

February 19, 2015

Southwest Power Pool

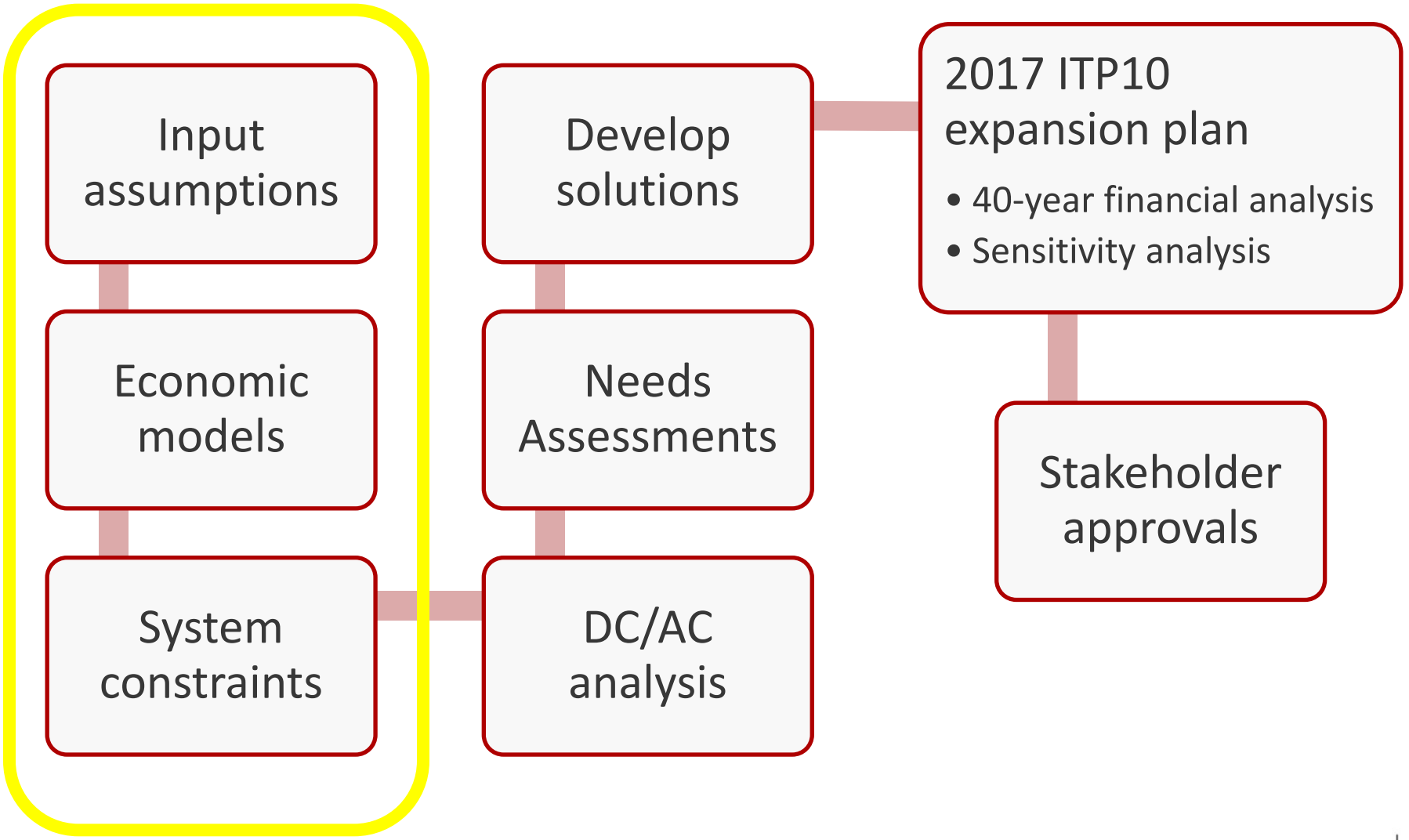
Overview of 2017 ITP10

- Integrated Transmission Planning Year 10 Assessment
- Study Year 2026
- Report will be sent to Board of Directors in January, 2017

ESWG Responsibilities

- Scope
- Futures
- Renewable Survey
- Load Forecast and Generator Review
- Resource and Siting Plans
- Economic Modeling Assumptions
- Policy and Economic Assessment
- Benefit Metrics
- Sensitivity Analysis
- Report

Study Process



Data Inputs

- Futures
  - How many Futures
- Renewable survey
  - Renewable Expansion
- Load and Generation review
  - 2015, 2020 & 2026 MDWG Model
  - Unit Retirements
- Resource plan
  - Prototypes
  - Wind Capacity Factor
  - Wind Accreditation
  - Zonal Capacity Margin %
- Siting
  - White paper

Data Inputs

- System topology
  - Approved ITPNT model set +…
  - Necessary modifications
- Fuel prices
- Emissions price
- External regions
- Generation parameters
- DC Ties
- Benchmarking
  - What data items?
  - Hurdle Rates
- Define constraints
  - Load Pocket Analysis?
  - AC Impacts?