Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

November 16th – 17th, 2016

SPP Corporate Offices – Little Rock, AR

• SUMMARY OF ACTIONS TAKEN •

1. None

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

November 16th – 17th, 2016

SPP Corporate Offices – Little Rock, AR

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC) 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 27 in-person participants and 37 web conference participants, representing 17 of 17 ESWG members. (Attachment 1 – November 16th-17th, 2016 Attendance List)

Agenda Item 1b – Receipt of Proxies

Chair Alan Myers (ITC) asked for any proxy statements; one proxy was identified. Jody Holland (SCMCN) named Eric Burkey (SCMCN) as his proxy. (Attachment 2 – Proxy Statements)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – November 16th-17th, 2016 Agenda)

Kurt Stradley (LES) made a motion; seconded by Al Tamimi (Sunflower) to adopt the agenda as modified. The motion was approved unanimously.

Agenda Item 2 – Review of Past Action Items

Kelsey Allen (SPP Staff) reviewed the list of past action items and asked for any comments or questions. (Attachment 4 – Past Action Items)

Agenda Item 3 – Consent Agenda

The consent agenda included the following items:

Meetings Minutes – October 20th, 2016 (Attachment 5 – October 20th, 2016 ESWG Minutes)

Alan Myers (ITC Great Plains) asked if any items should be removed from the consent agenda.

The consent agenda was approved unanimously.

Agenda Item 4 – 2017 ITP10 Study Schedule

Juliano Freitas (SPP) reviewed the 2017 ITP10 schedule with the group. Final assessments including benefit metric calculations are on track for completion by the December meeting. The group asked about the logistics of reviewing comments on the 2017 ITP10 report and agreed that a call to discuss and approve the first week in January, 2017 would work best. (Attachment 6 – 2017 ITP10 Schedule)

Agenda Item 5 – ITP Manual Task Force Update

Amber Greb (SPP Staff) gave an update on the activities of the ITP Manual Task Force (ITPMTF). The group is currently finalizing the new outline of the ITP manual and expects to begin reviewing language brought by SPP staff crafted based on working group approvals. Amber reminded the group that once the scope is standardized and the manual is complete it will become an official document that will become a part of the SPP Revision Request process. (Attachment 7 – ITPMTF Update)

Agenda Item 6 – 2017 ITP10 Portfolio Consolidation and Project Staging

Nikki Roberts (SPP Staff) presented the draft results of portfolio consolidation and staging of projects based on the criteria to create a CPP and a non-CPP portfolio of projects. Futures 1 and 2 economic projects were consolidated based on a weighted APC calculation of 75% of Future 1 benefit and 25% of Future 2 benefit. Projects were staged by interpolating benefits between the study (2025) and staging (2020) year, selecting the year the project's B/C was greater than 1.0. Portfolio benefit summaries were reported for economic project portfolio and reported in 1-year B/C ratios. Alan Myers (ITC) questioned the reliability project need date of 1/1/2020 because it was arbitrarily chosen based on the definition of the off-peak model (January 4th, 5am) and would bring the project into the short-term reliability window. (Attachment 8 – 2017 ITP10 Portfolio Consolidation and Project Staging)

Agenda Item 7 – Incorporating Additional Analysis in the 2017 ITP10

Chris Jamieson (SPP Staff) reviewed the additional analysis being performed by SPP staff for the 2017 ITP10. Chris started with a methodology to develop a set of recommended projects and need dates from the Future 1/Future 2 consolidated and Future 3 portfolios. Natasha Henderson (GSEC) requested that SPP staff report on the likelihood that a transmission project is being driven by proxy generation from the resource plan.

Chris Jamieson (SPP Staff) then gave an overview and preliminary results of the "sidebar" analysis that incorporated previously issued NTC projects and other model updates into an updated constraint assessment, economic assessment, and reliability assessment.

SPP staff was also made aware of an issue with the SPP wind profiles being represented in Coordinated Universal Time (UTC) rather than local time zones. SPP staff did an assessment of the impact of correcting the issue by reviewing changes generator capacity factors, reliability unit commitments, flowgate congestion, and reliability needs. SPP staff found that the needs remained very similar and will continue investigation by assessing the impact to the APC benefits provided by the selected projects. The updated profiles will be included in all future analysis.

Chris Jamieson (SPP Staff) then gave an overview of the drivers, background and analysis being performed to develop alternative project recommendations for two target areas, Eastern Seams and Texas Panhandle. Preliminary results were provided for the Texas Panhandle analysis.

(Attachment 9 - 2017 ITP10 Additional Analysis) (Attachment 10 - 20161117_2017 ITP10 Wind Profiles)

Agenda Item 8 – ITP Scope Standardization

Agenda Item 8a – Discussion Items Checklist and Schedule

Kelsey Allen (SPP Staff) briefly reviewed a checklist of discussion items being brought to the group for discussion and the proposed date the group should expect to see them on the agenda as well as an expected date of working group approval. (Attachment 11 – ITP Scope Standardization - WG Ownership and Timeline)

Agenda Item 8b – Chronic Operational Issues Criteria

Will Tootle (SPP Staff) reviewed the proposed criteria for defining operational needs in the new ITP process. The group had questions regarding some of the specifics of the criteria and the thresholds developed and requested general clarity. SPP operations staff developed most of these criteria through reviewing actual data over the last couple years and correlating that information to top pain points related to operating the system. Antoine Lucas (SPP Staff) reiterated that the request of the TPITF was to identify why current operation issues are not being identified in planning assessments and determine if the drivers are related to proxy study assumptions. These criteria would allow development of solutions to address current issues when that is the case. (Attachment 12 – TPITF - Chronic Operational Issues Criteria) (Attachment 13 – Chronic Issues Summary_October_2016)

Agenda Item 8c – Resource Expansion Plan

Josh Ross (SPP Staff) reviewed a proposal for standardizing development of SPP and external conventional resource expansion plans. Some members of the group suggested that the language in the

manual be left open for SPP staff and the ESWG to make adjustments to the process and results as well as to look into better software coordination across SPP groups performing similar analysis. Josh then reviewed a proposal for including additional wind for export in ITP assessments. After discussion, the group determined that it was not appropriate to standardize this item at this time due to the implications it could have and the fact that other efforts at SPP to address those issues are currently underway. (Attachment 14 – ITP Resource Expansion Plan)

Agenda Item 8d – Resource Siting Plan

Chris Jamieson (SPP Staff) gave an overview of the resource siting plan utilized in the 2017 ITP10 for conventional, wind and solar generation. These methodologies would generally be the standard proposal for future ITP studies. (Attachment 15 – ITP Resource Siting Plan)

Agenda Item 8e – Policy Survey

Liz Gephardt (SPP Staff) reviewed a proposal for standardization of the renewable policy survey that would save both SPP staff and stakeholder time by standardizing percentages of load and/or generation by utility and state to add renewable generation. The exact percentages are to be worked out through continued discussions at ESWG and engagement of CAWG members as well. (Attachment 16 – ITP Policy Survey)

Agenda Item 8f – Wind Pricing

[This item was not covered in the allotted time] (Attachment 17 – ITP Wind Modeling)

Agenda Item 9 – 2017 ESWG Meeting Schedule

Kelsey Allen (SPP Staff) reviewed the proposed locations for the quarterly meetings in conjunction with TWG. The group expressed no concern with the proposal and encouraged SPP staff to look for opportunities to schedule joint ESWG/TWG meeting time when agenda items would warrant it. (Attachment 18 – ESWG.TWG Meeting Locations 2017)

Agenda Item 10 – EGEAS Overview and Discussion

[This item was not covered in the allotted time]

Agenda Item 11 – ESWG Charter Discussion (LOLE and SAWG)

Kelsey Allen (SPP Staff) briefly informed the group that the charter was bring brought to the group for review specifically to address the desire of the new Supply Adequacy Working Group (SAWG) to take over responsibility of reviewing the Loss of Load Expectation (LOLE) studies performed by SPP. The group agreed that the LOLE would be a better fit under purview of the SAWG and asked for the suggested edits to be made and sent out for review. (Attachment 19 – ESWG Charter)

Closing Items

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

The meeting was adjourned at 12:00 PM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Name	Email	Company	Attendance
Aaron Pupa	apupa@lspower.com		Webex
Adam McKinnie		MO PSC	In Person
agreb	agreb@spp.org		Webex
Al Tamimi		SEPC	In Person
Alan Myers		ITC	In Person
Amber Greb		SPP	In Person
Angie Anderson		SEPC	In Person
Anita	asharma@aep.com		Webex
Antoine Lucas		SPP	In Person
AntonioSPP	abarber@spp.org		Webex
Ben Abing	babing@itctransco.com		Webex
Bethany King		EDE	In Person
Bill Leung (NPRB)	bleung@bjleung.com		Webex
Bret Toplyn	bret.toplyn@us.abb.com		Webex
Brian Rounds (AESL)	brian.rounds@aeslconsulting.com		Webex
Chris Giles	cgiles@tcec.coop		Webex
Chris Jamieson		SPP	In Person
Chris Matthes	camatthes@aep.com		Webex
Clayton Mayfield	cmayfield@spp.org		Webex
David Binkley	dbinkley@itctransco.com		Webex
Don Le (NEET)	don.le@nee.com		Webex
Eric Burkey		SCMCN	In Person
Gayle Nansel		WAPA	In Person
Gunnar Shaffer	gshaffer@spp.org		Webex
James Mitschke	j.mitschke@occemail.com		Webex
James Remley	james.remley@westarenergy.com		Webex
Jamie Hajek	jamie.hajek@northwestern.com		Webex
Jarrod Wolford		NTEC	In Person
Jason Chaplin (OCC)	j.chaplin@occemail.com		Webex
Jason Davis		SPP	In Person
Jason Mazigian	jmazigian@bepc.com		Webex
Jason Shook		GDS/ETEC	In Person
Jeff Knottek	jeff.knottek@cityutilities.net		Webex
Jeremy Harris (WERE)	jeremy.harris@westarenergy.com		Webex
Jeremy Severson		BEPC	In Person
Joe Fultz (GRDA)	jfultz@grda.com		Webex
John Boshears (SPRM)	john.boshears@cityutilities.net		Webex
Jon Iverson	jiverson@oppd.com		Webex
Jordan Schmick	jordan.h.schmick@xcelenergy.com		Webex
Josephine Daggett		WAPA	In Person
Josh Ross		SPP	In Person
Kelsey Allen	kallen@spp.org	SPP	In Person
Kevin Foflygen (SPRM)	kevin.foflygen@cityutilities.net		Webex
Kirk Hall		SPP	In Person
Kurt Stradley		LES	In Person
Leon Howell		OGE	In Person

Liz Gephardt		SPP	In Person
Meena (PUCT)	meena.thomas@puc.texas.gov		Webex
Michael Massery		AECC	In Person
Michael Watt (OMPA)	mwatt@ompa.com		Webex
Michael Wegner		ITC	In Person
Nikki Roberts	nroberts@spp.org		Webex
Pat Hayes	phayes@ameren.com		Webex
Pat McCool		KCPL	In Person
Raj Pudhota	rpudhota@quanta-technology.com		Webex
Randy Collier (CUS)	randy.collier@cityutilities.net		Webex
Ross Hohlt	dhohlt@ameren.com		Webex
Sam Loudenslager		SPP	In Person
Sarah Pettus	sarah@windcoalition.org		Webex
Shawnee Claiborn-Pinto	shawnee.claiborn-pinto@puc.texas.gov		Webex
Steve Gaw	rsgaw1@gmail.com		Webex
Tim Owens		NPPD	In Person
Todd Tadych (DATC)	ttadych@atcllc.com		Webex
Wayne Penrod		Sunflower	In Person

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

November 16-17, 2016

SPP Corporate Office/Little Rock, AR

• ATTENDANCE LIST •

Name	Company
Jason Davis	SPP
Michael Wegner	ITC
Liz Gephardt	SPP
AL Tamimi	SEPC
Chris Jamieson	SPP
Angie Anderson	SEPC
Sam Loudenslager	SPP Staff
Kirk Hall	SPP
Alan Myers	ITC
Tim Owens	NPPD
Bethany Kiley	EDE
Adam McKinnie	MO PSC
Kelsey Allen	SPP

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

November 16-17, 2016

SPP Corporate Office/Little Rock, AR

• ATTENDANCE LIST •

Name	Company
Kelsey Allen	SPP
Josh Ross	SPP
Tim Owens	NPPD
KURT STRADLEY	LES
Jason Davis	SPP
Kirk Hall	SPP
Chris Jamison	SPP
Amber Gregs	SPP
Adam McKinnie	MO PSC
Jeremy Severson	BEPC
Antaine Lucas	SPP
Angie Anderson	SEPC
Eric Burkey	SCMCN
Josephine Degyeft	WAPA
JASON SHOOK	GDS/ETEC
Jarrod Walford	NTEC
AL Tamimi	SEPC

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

November 16-17, 2016

SPP Corporate Office/Little Rock, AR

• ATTENDANCE LIST •

Name	Company
Wayne Penrod	Sunflower
Michael Massery	AECC
Pat McCool	KCPL
Bethany Kily	EDE
Gayle Wansley	WAPA
Leon Howell	OGE

1. **Jody Holland (SCMCN) proxy to Eric Burkey (SCMCN)**

From: Jody Holland [mailto:JHolland@gridliance.com]
Sent: Monday, September 26, 2016 12:49 PM
To: Myers, Alan K. <amyers@ltctransco.com>; Kirk Hall <khall@spp.org>
Cc: Eric Burkey <EBurkey@gridliance.com>; Jody Holland <JHolland@gridliance.com>
Subject: [EXT] proxy for 11/16-17 ESWG in Little Rock

Alan/Kirk,
Eric will have my proxy for the 11/16-17 ESWG in Little Rock. Thanks.

Jody Holland
Director, Transmission Planning
South Central MCN, LLC
Midcontinent MCN, LLC
MidAtlantic MCN, LLC
Cell: 501-681-5950
jholland@gridliance.com

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Blackstone Portfolio Company

ECONOMIC STUDIES WORKING GROUP

November 16th – 17th, 2016

SPP Corporate Offices – Little Rock, AR

• A G E N D A •

Wednesday 1:00pm – 5:00pm

1. Administrative Items
    a. Call to Order, Introductions ..... Alan Myers (5 minutes)
    b. Receipt of Proxies ..... Kelsey Allen (1 minute)
    c. Review of Agenda[1] ..... Alan Myers (1 minute)
2. Review of Past Action Items[1] ..... Kelsey Allen (5 minutes)
3. Consent Agenda[1] (Approval Item) ..... Alan Myers (5 minutes)
    a. Approval of Meeting Minutes – October 20th, 2016
4. 2017 ITP 10 Study Schedule[1] ..... Juliano Freitas (5 minutes)
5. ITP Manual Task Force Update[1] ..... Amber Greb (5 minutes)
6. 2017 ITP10 Portfolio Consolidation and Project Staging[1] ..... SPP Staff (30 minutes)
7. Incorporating Additional Analysis in the 2017 ITP10 ..... Chris Jamieson (45 minutes)
    a. Alternative Project Analysis
    b. Model Update Impact Analysis
8. ITP Scope Standardization ..... SPP Staff (120 minutes)
    a. Discussion Items Checklist and Schedule (Kelsey Allen)
    b. Chronic Operational Issues Criteria[1] (Will Tootle)
    c. Resource Expansion Plan[1] (Josh Ross)

Thursday 8:00am – 12:00pm

8. ITP Scope Standardization (Continued) ..... SPP Staff (120 minutes)
    d. Resource Siting Plan[1] (Chris Jamieson)
    e. Policy Survey[1] (Liz Gephardt)
    f. Wind Pricing (Josh Ross)

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[1] Background Material Included

9. 2017 ESWG Meeting Schedule (Approval Item) ..... All (5 minutes)

10. EGEAS[2] Overview and Discussion ..... Juliano Freitas (30 minutes)

11. ESWG Charter Discussion (LOLE and SAWG)[1] ..... Kelsey Allen (15 minutes)

12. Closing Items ..... All (5 minutes)
    a. Summary of Action Items (Kelsey Allen)
    b. Future Meetings
        i. December 8th, 2016: 8th Floor AEP Offices, Dallas, TX
        ii. January 12th, 2017: 8th Floor AEP Offices, Dallas, TX
        iii. March 16th, 2017: 8th Floor AEP Offices, Dallas, TX
        iv. April 20th, 2017: 8th Floor AEP Offices, Dallas, TX
        v. June 15th, 2017: 8th Floor AEP Offices, Dallas, TX

[2] Electric Generation Expansion Analysis System (EGEAS)

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

November 16th – 17th, 2016

	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 23rd, 2012	In Progress Staff	A draft resource siting whitepaper will be developed for review mid-2016.
151	Staff to look into optional software tools for use in ITP studies.	May 20th, 2015	In Progress Staff	Staff is meeting with software vendors and users and expects to have a recommendation on any potential resource planning software changes by 4th quarter 2016.
160	SPP Staff and the ESWG are to formalize standard procedures for data requests and member review of information related to ITP studies.	January 21st, 2016	In Progress Staff/ESWG	Combined item representative of AI148 and AI149.
161	Staff to report on carbon emissions as the 2017 ITP10 study moves forward through the different milestones.	February 24th-25th, 2016	In Progress Staff	
163	SPP Staff and members to prepare for discussion on scope standardization and prioritization of discussion items.	April 21st, 2016	In Progress Staff/Members	
165	ESWG to review the assumed benefit of mandated reliability projects	May 13th, 2016 RARTF	In Progress ESWG	
166	ESWG to review the impacts of using the system reconfiguration hybrid approach for the Assumed Benefit of Mandated Reliability Projects	May 13th, 2016 RARTF	In Progress ESWG	
167	ESWG to review the classification of projects in the ITP process	May 13th, 2016 RARTF	In Progress ESWG	
168	Staff and the ESWG to evaluate the issues seen in the DC to AC model	May 18th-19th,	In Progress	

	conversion process.	2016	Staff/ESWG	
169	Staff to investigate the requirements for approval of a new standard ITP scope in order to determine the date of approval by the working groups needed prior to final approval by MOPC and the Board.	June 16th, 2016	~~In Progress~~Complete Staff	7/21: Approval by April, 2017 for July MOPC/BOD approval. 8/23: Potential for work needing to be complete by January, 2017 in order to go through all necessary working groups.
170	Staff to coordinate with other SPP groups regarding requirements and opportunities for standardization of requesting and utilizing peak load data.	June 16th, 2016	~~In Progress~~Complete Staff	August 23rd: Staff brought a proposal to coordinate data with the SAWG. October 20th: ESWG approved a methodology for the ITP standard scope. Discussions should continue with SAWG for coordination of methodology, as appropriate.
171	Staff to investigate coordination opportunities regarding request for member hourly load data.	June 16th, 2016	~~In Progress~~Complete Staff	
172	Staff to develop examples and language for tackling synergies of powerflow and economic generation data.	June 16th, 2016	In Progress Staff	October 20th: ESWG approved a methodology for the ITP standard scope. Discussions should continue with SAWG for coordination of methodology, as appropriate.
173	Staff to develop a process for annual update of the economic model with vendor data.	June 16th, 2016	In Progress Staff	
174	Staff to develop criteria and methodology to developing resource plans absent a software tool.	June 16th, 2016	In Progress Staff	
177	Staff to develop a checklist of decision points for development of the ITP standard scope.	July 21st, 2016	In Progress Staff	September 15th: Include timeline for bringing items to each meeting. October 20th: Still vetting internally. Should be

				ready for member consumption prior to November meeting. November 16th: Will be discussed in meeting.
182	SPP Staff to post models and data utilized for the 2017 ITP10 side-bar analysis when complete.	September 15th, 2016	In Progress Staff	
183	SPP Staff to perform the outage analysis to determine the appropriate APC benefit % to utilize in the mitigation of transmission outages benefit metric in the first part of 2017.	September 15th, 2016	In Progress Staff	
184	Stakeholders to submit comments on the chronic operational issues criteria to SPP Operations (Will Tootle, wtootle@spp.org) within the next couple of weeks.	October 20th, 2016	In Progress Stakeholders	

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Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

October 20th, 2016

OMPA Board Room – Edmond, OK

• SUMMARY OF ACTIONS TAKEN •

1. Accepted SPP staff's proposal for updating peak load, hourly load, and monthly peak and energy data items (ITP scope standardization).
2. Accepted SPP staff's proposal for updating load and loss factor and demand group (ownership) mapping data items (ITP scope standardization).
3. Accepted SPP staff's proposal for utilizing vendor generator names and vendor data as a starting point for generator data review (ITP scope standardization).
4. Approved SPP staff's recommendation for updating fuel and emission prices (ITP scope standardization).
5. Approved SPP staff's recommendation for DC tie modeling in the economic models (ITP scope standardization).
6. Approved SPP staff's proposal for modeling of future renewable generation, as modified (ITP scope standardization).

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

October 20th, 2016

OMPA Board Room – Edmond, OK

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:02 AM, welcomed those in attendance, and asked for introductions.

There were 18 in-person participants and 43 web conference participants, representing 17 of 17 ESWG members. (Attachment 1 – October 20th, 2016 Attendance List)

Agenda Item 1b – Receipt of Proxies

Chair Alan Myers (ITC) asked for any proxy statements; four proxies were identified. Al Tamimi (Sunflower) named Wayne Penrod (Sunflower) as his proxy and Jody Holland (SCMCN) named Eric Burkey (SCMCN) as his proxy. (Attachment 2 – Proxy Statements)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – October 20th, 2016 Agenda)

> **Tim Owens (NPPD) made a motion; seconded by Kurt Stradley (LES) to adopt the agenda as modified. The motion was approved unanimously.**

Agenda Item 2 – Review of Past Action Items

Kelsey Allen (SPP Staff) reviewed the list of past action items and asked for any comments or questions. (Attachment 4 – Past Action Items)

Agenda Item 3 – Consent Agenda

The consent agenda included the following items:

> Meetings Minutes – September 15th, 2016 (Attachment 5 – September 15th, 2016 ESWG Minutes)

Alan Myers (ITC Great Plains) asked if any items should be removed from the consent agenda.

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

Agenda Item 4 – Study Schedules

Agenda Item 4a – 2017 ITP10

Juliano Freitas (SPP) reviewed the 2017 ITP10 schedule with the group. Staff has completed the Project Grouping milestone as scoped and is continuing on with Portfolio Consolidation and Project Staging to be complete by the November meeting. Final assessments including benefit metric calculations are on track for completion by the December meeting. (Attachment 6 – 2017 ITP10 Schedule)

Agenda Item 5 – Incorporating Additional Analysis in the 2017 ITP10

Juliano Freitas (SPP Staff) reviewed the additional analysis being performed to supplement the work completed so far in the 2017 ITP10 that will be used to inform a recommended plan to the MOPC and Board. Tim Owens (NPPD) expressed concern with the volume of information that could be brought to the Stakeholders so late in the process. SPP staff explained that the additional analysis performed for

the Multi-Variable Portfolio and the "Side-Bar" won't produce additional portfolios but rather recommendations regarding currently selected projects or alternative project recommendations in certain key areas for consideration. Gayle Nansel (WAPA) pointed out the misnomer of "model corrections" being used to describe the changes made for the "Side-Bar" analysis, stating that many of these changes were model updates made due to timing.

In order to bring the study to completion, a final recommended plan must be developed for consideration by the Stakeholders. This includes incorporation of the additional analysis as well as consolidation of the CPP and reference case portfolios. The group discussed the similarities between the current plans and the idea of developing a core set of projects, with consideration of additional projects that may hedge against the future in general and specifically related to the outcome of the CPP. (Attachment 7 – 2017 ITP10 Additional Analysis)

Agenda Item 6 – ITP Scope Standardization

Agenda Item 6a – Discussion Items Checklist

Kelsey Allen (SPP Staff) gave an update on the discussion items checklist. It is currently being reviewed internal to SPP for completeness and reasonableness and will be rolled out to the group before the November meeting.

Agenda Item 6b – Chronic Operational Issues Criteria

Will Tootle (SPP Staff) reviewed the draft criteria for defining potential operational needs to be evaluated in the new ITP process. The current draft describes different issues experienced in operations that could warrant a planning solution. Frequency and/or cost thresholds were applied to those issues to develop a list of potential candidates based on the latest data for informational purposes. Will requested that the group consider the different issues and provide feedback, including recommended adjustments to the frequency and cost thresholds to be used, within the next couple of weeks. (Attachment 8 – Chronic Issues Summary_October_2016) (Attachment 9 – TPITF - Chronic Operational Issues Criteria)

ACTION ITEM: Stakeholders to submit comments on the chronic operational issues criteria to SPP Operations (Will Tootle, wtootle@spp.org) within the next couple of weeks.

Agenda Item 6c – Load and Generation Review

Clayton Mayfield (SPP Staff) reviewed SPP staff's proposal for standardization of the load and generation review study milestones. The proposals generally involve utilization of available data from either information submitted through the MDWG model development process or leveraging vendor data supplied with each economic model release. Many of these were short-term recommendations with a longer term goal to coordinate potential changes and standardization of a methodology for all common data across SPP studies, specifically coordinating with the newly formed Supply Adequacy Working Group (SAWG) on economic data. There was discussion regarding the level of company granularity that is available in leveraging vendor data and whether or not it would be sufficient in the future. A methodology should be developed long term to achieve the desired model granularity.

> **Leon Howell (OGE) made a motion; seconded by Kurt Stradley (LES) to accept SPP staff's proposal for updating peak load, hourly load, and monthly peak and energy data items. The motion was approved unanimously.**
>
> **Kurt Stradley (LES) made a motion; seconded by Wayne Penrod (Sunflower) to accept SPP staff's proposal for updating load and loss factor and demand group (ownership) mapping data items. The motion was approved unanimously.**
>
> **Leon Howell (OGE) made a motion; seconded by Done Le (NEET) to accept SPP staff's proposal for utilizing vendor generator names and vendor data as a starting point for generator data review. The motion was approved unanimously.**

(Attachment 10 - ITP Scope Standardization – Load and Generation Review)

Agenda Item 6d – Economic Model Data Items

Kelsey Allen (SPP Staff) reviewed recommendations for modeling of fuel and emission prices and DC ties with the Texas and Western Interconnections in the economic model. These recommendations would be implemented in a reference case type future with potential adjustments to be discussed during the scoping (assumptions) phase of each ITP study.

> **Wayne Penrod (Sunflower) made a motion; seconded by Bethany King (EDE) to approve SPP staff's recommendation for updating fuel and emission prices. The motion was approved unanimously.**

There was some concern expressed by some members with both capping the DC tie transactions to long-term firm transmission service and the modeling of those transactions based on historical flows rather than economic signals.

> **Bennie Weeks (SPS) made a motion; seconded by Leon Howell (OGE) to approve SPP staff's recommendation for DC tie modeling in the economic models. The motion was approved with four abstentions, Wayne Penrod (Sunflower), Alan Myers (ITC), Gayle Nansel (WAPA), and Jeremy Severson (Basin).**

(Attachment 11 - ITP Scope Standardization – Economic Model Data Items)

Agenda Item 6e – Resource Plan

Josh Ross (SPP Staff) began review of SPP staff's proposals for standardization of resource planning, beginning with a methodology for determining renewable additions. The original (posted background materials) proposal was modified to what is seen in the attachments to these minutes.

> **Natasha Henderson (GSEC) made a motion; seconded by Wayne Penrod (Sunflower) to approve SPP staff's proposal for modeling of future renewable generation, as modified. The motion was approved unanimously.**

Josh continued discussion modeling of future renewable generation for exporting out of the SPP system. The group agreed that some level of future renewable export should be considered but expressed concerns regarding the lack of transmission service for non-firm resources and overall cost allocation impacts. The SPP Strategic Planning Committee formed the Export Pricing Task Force (EPTF) to specifically address these concerns. Michael Wegner (ITC) suggested adjusting the proposed calculation to consider historical trends to extrapolate a new ratio of export/total wind instead of using a ratio based on existing in order to consider a potential rate of increase of wind installed in SPP for export. (Attachment 12 – ITP Scope Standardization - Resource Plan)

Agenda Item 6f – Resource Siting Plan

[This item was not covered in the allotted time]

(Attachment 13 – ITP Scope Standardization - Resource Siting Plan)

Agenda Item 7 – 2017 ESWG Meeting Schedule

Kelsey Allen (SPP Staff) briefly mentioned the remaining unscheduled meetings for 2017 that would be in conjunction with the TWG. SPP has internally proposed locations and dates and will be sending those out for review by the Stakeholders.

Closing Items

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

List of action items from the meeting:

1. Stakeholders to submit comments on the chronic operational issues criteria to SPP Operations (Will Tootle, wtootle@spp.org) within the next couple of weeks.

The meeting was adjourned at 2:45 PM.

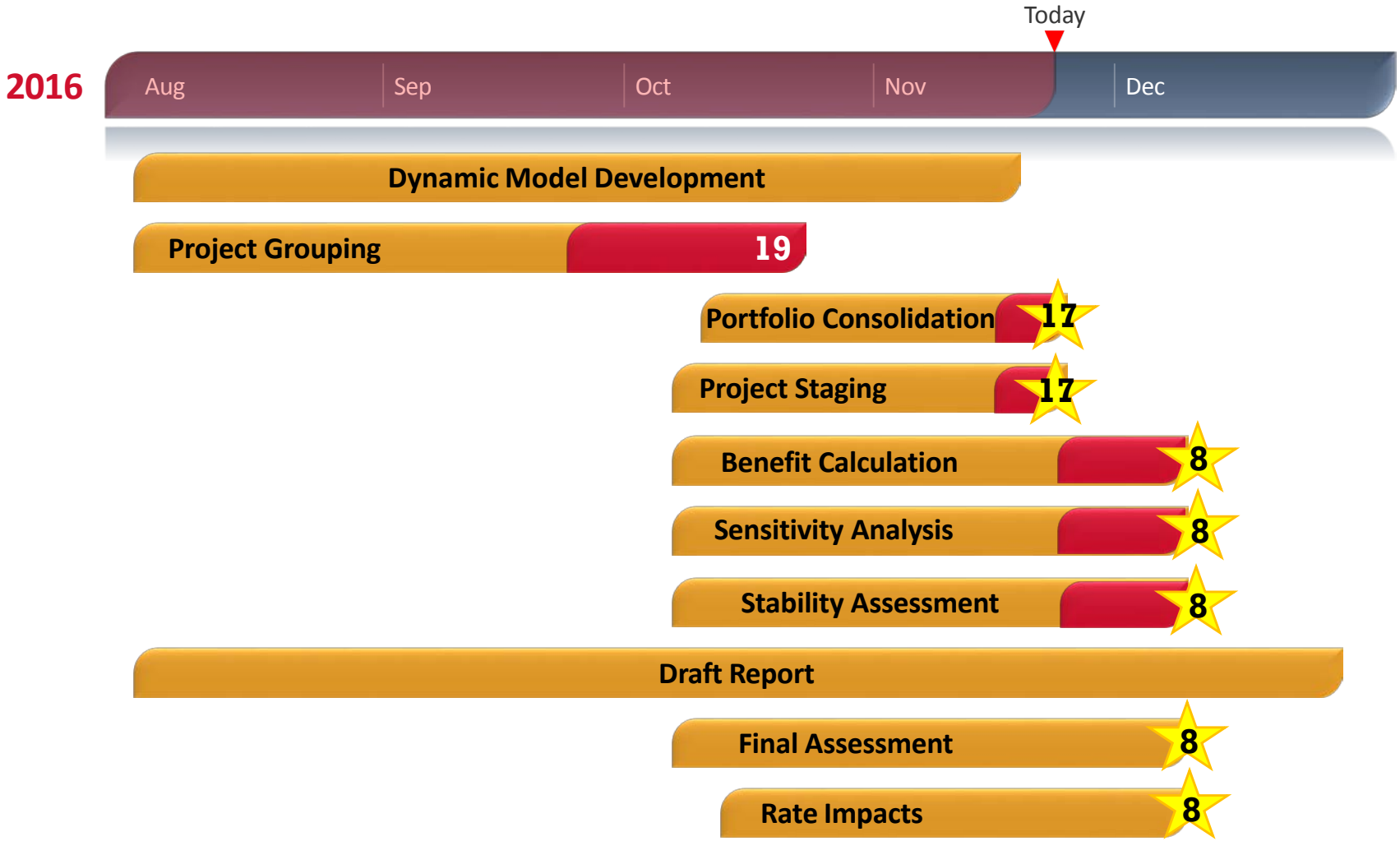
Respectfully Submitted,

Kelsey Allen
ESWG Secretary

2017 ITP10 Schedule

ESWG

November 16th, 2016



WG Approval

Member Review/Feedback Period

Milestone Period

ITP Manual Task Force (ITPMTF)

ESWG

November 16, 2016

Amber Greb

ITP Manual TF Members

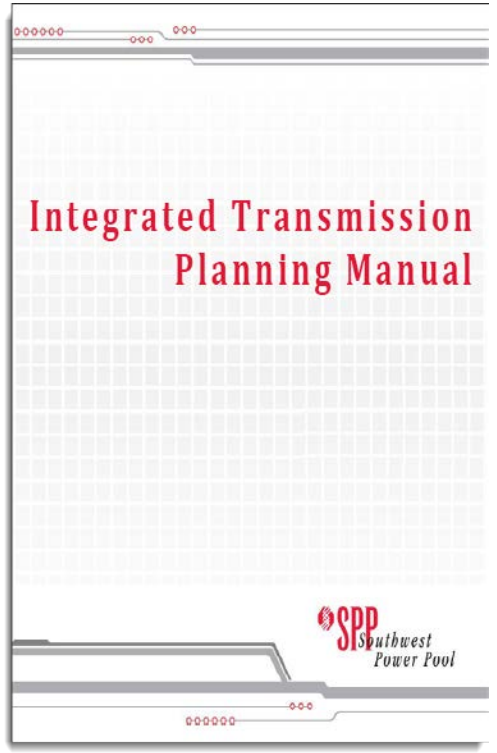
- **Michael Wegner**– *Chair*
  - ITC Holdings
- **Pat McCool-** *Vice Chair*
  - Kansas City Power & Light
- **Amber Greb**– *Secretary*
  - Southwest Power Pool
- **Dustin Betz**
  - Nebraska Public Power District
- **Aravind Chellappa**
  - Xcel Energy/SPS
- **Steve Gaw**
  - Wind Coalition
- **Nathan McNeil**
  - Westar Energy
- **Gayle Nansel**
  - Western Area Power Administration
- **Tim Owens**
  - Nebraska Public Power District

ITP Manual Task Force Update

- Task force working to finalize the outline of document
- Staff working on language based on approvals
- Face to face meeting Nov. 17th

Standardized Study Scope

- **Standard Documents**
  - Standardized scope (ITP Manual)
    - Methodologies and criteria that guide the ITP study process
    - Will remain consistent from study to study
  - Assumptions document
    - Houses scope items that will require Stakeholder review and approval with each new study
    - Approved by the appropriate working groups during the scope development phase of the planning cycle
  - RR Process for changes to standardized scope items
    - Once approved, modifications to the manual will be submitted through the SPP Revision Request (RR)



TWG and ESWG will review and approve the scope items that will be standardized and the scope items that will be a part of the assumptions document and update the ITP Manual accordingly

2017 ITP10 Consolidation and Staging

ESWG

November 16th, 2016

Consolidation of Economic Portfolios

- The ESWG approved 2 final portfolios to be presented to MOPC/BOD:
  - F1 and F2 portfolio projects are to be consolidated into portfolio, the "CPP Portfolio."
  - F3 portfolio projects will stand alone as the Reference Case Portfolio, or "non-CPP Portfolio."

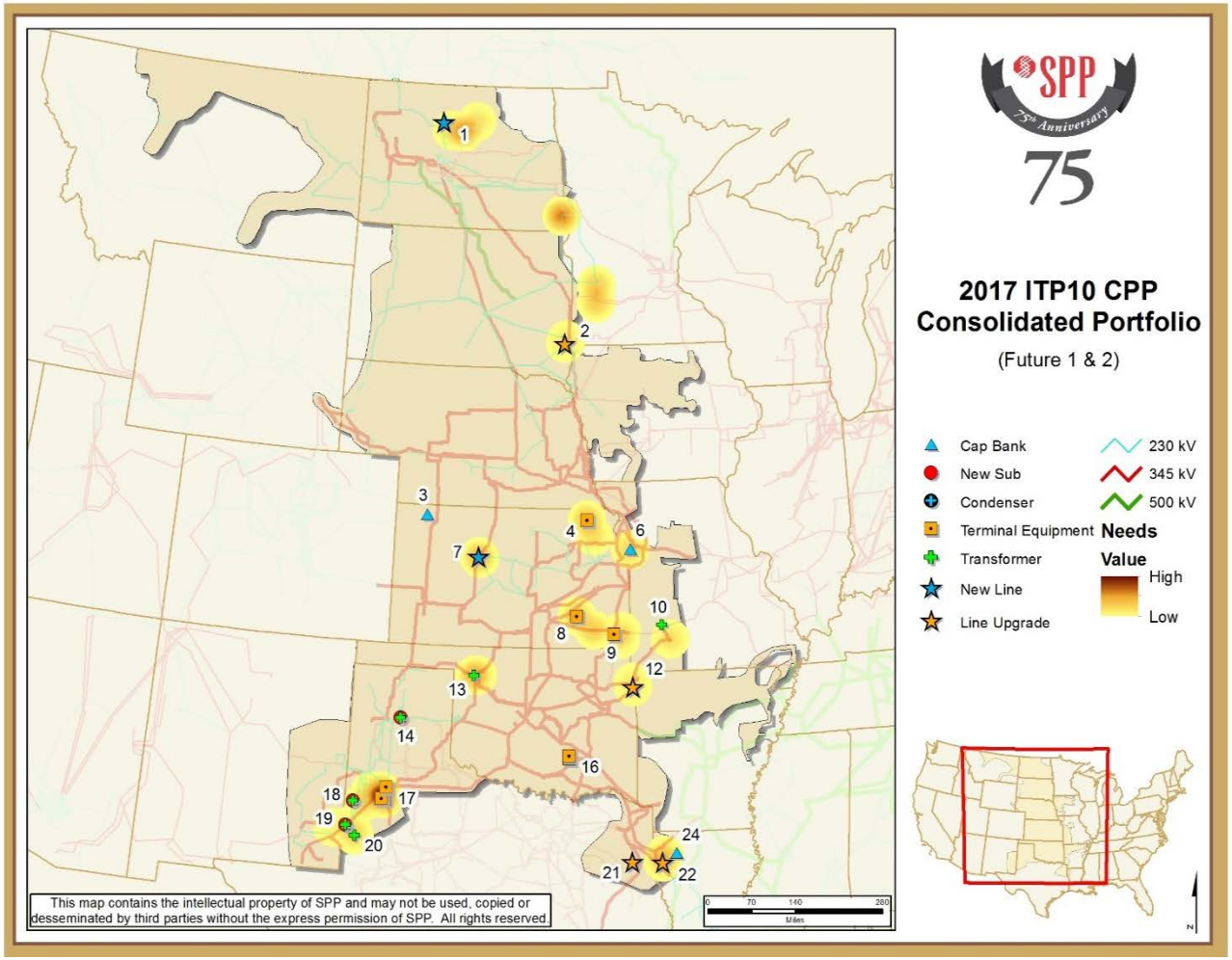
- The CPP Portfolio will consist of projects that meet the 0.9 B/C threshold calculated by taking 75% of the project's benefit in F1 and 25% of the project's benefit in F2.

- Benefits of economic projects in the CPP futures were evaluated on the respective future's base case and the CPP Consolidated Reliability portfolio.

Staging of Economic Projects

- Incremental benefit of each economic project was calculated for the study and staging years.
- The reference case portfolio benefits were evaluated in Future 3, and the CPP portfolio benefits were evaluated in Futures 1 and 2.
- CPP project benefits were weighted consistent with the Consolidation process (75% in F1, 25% in F2).
- Economic projects given an in-service date for the first year (2020 or later) that the B/C ratio was greater than 1.0 based on interpolation between the staging and study year results.

Consolidated CPP Portfolio



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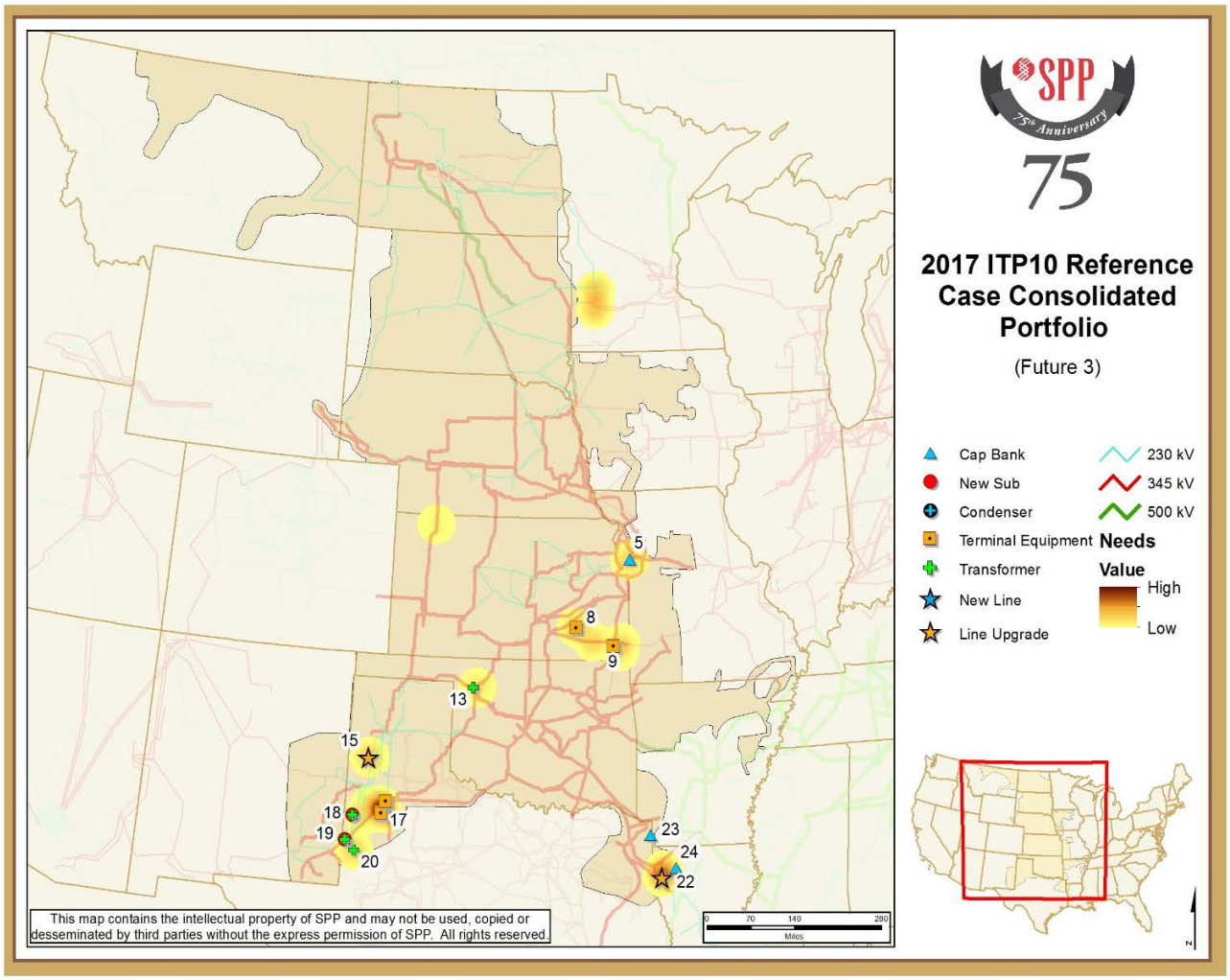
Consolidated CPP Portfolio - Reliability

General Description	Cost Estimate	Location (Zone)	Staging Date
Rebuild 5.5-mile 138kV line from Knox Lee to South Texas Eastman and upgrade any necessary equipment to increase the branch ratings to 371/470 MVA.	$8,456,250	AEP	6/1/2022
Install 28.8-MVAR capacitor bank at Port Robson 138 kV	$2,306,250	AEP	6/1/2025
Install two 14.4-MVAR capacitor banks (28.8 total MVAR) at Atwood 115kV substation. Install 14.4-MVAR capacitor bank at Seguin Tap 115kV substation.	$2,389,707	MIDW	6/1/2024
Tap the existing 230kV line from Hobbs to Yoakum and the existing 115kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115kV transformer at new Hobbs - Yoakum Tap substation.	$9,953,077	SPS	1/1/2020
Tap the the Nichols to Grapevine 230kV line to construct new substation. Install a new 230/115kV transformer at Nichols - Grapevine tab substation. Construct new 2-mile 115kV line from Martin to Nichols/Grapevine tap substation. Install terminal upgrades at Martin to accommodate new 115kV line from the Nichols/Grapevine tap substation.	$14,936,215	SPS	1/1/2020

Consolidated CPP Portfolio - Economic

General Description	Cost Estimate	Location (Zone)	Staging Year
Install a 345/161 kV transformer at Morgan substation	$8,661,250	AECI	1/1/2020
Rebuild 11.2-mile 138kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	$17,015,000	AEP	1/1/2023
Rebuild 2.1-mile 161kV line from Siloam Springs (AEP)-Siloam Springs City (GRDA) and upgrade terminal equipment at Siloam Springs (AEP) and/or Siloam Springs City (GRDA) to increase the rating of the line between the substations to at least 446/446 (SN/SE)	$5,185,885	AEP/GRDA	1/1/2020
Add 2 ohm Series reactor to Northeast - Charlotte 161 kV line	$512,500	KCPL	1/1/2020
Build a new second 230 kV line from Knoll to Post Rock.	$3,389,019	MIDW	1/1/2020
Install one (1) 138kV phase shifting transformer at Woodward EHV along with upgrading relay, protective, and metering equipment, and all associated and miscellaneous materials.	$7,459,438	OGE	1/1/2020
Upgrade any necessary terminal equipment at Tupelo and/or Tupelo Tap to increase the rating of the 161kV line between the two substations to a summer and winter emergency rating of 169/201 MVA.	$102,500	SPA/WFEC	1/1/2020
Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115kV line between the two substations to a summer emergency rating of 175 MVA.	$969,942	SPS	1/1/2020
Tap the intersection of the 230kV line from Tolk to Yoakum and the 115kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115kV transformer at new substation.	$11,961,951	SPS	1/1/2020
Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	$7,423,880	SPS	1/1/2020
Tap the existing 230kV line from Hobbs to Yoakum and the existing 115kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115kV transformer at new Hobbs - Yoakum Tap substation.	$9,953,077	SPS	1/1/2020
Build a new double circuit 115 kV line from Magic City to a point on the Logan - Mallard 115 kV line that minimizes the distance between the new substation and the cut-in point. Bisect the Logan - Mallard 115 kV line to cut-in the new double circuit 115 kV line.	$3,075,000	WAPA/XEL	1/1/2021
Rebuild 1.0 mile 115 kV line from Lawrence - Sioux Falls Upgrade terminal equipment at Lawrence and/or Sioux Falls to increase the rating of the line between the substations to 398/398 (SN/SE)	$1,383,750	WAPA/XEL	1/1/2021
Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138kV line between the two substations to a summer emergency rating of 110 MVA.	$244,606	WR	1/1/2020
Upgrade any necessary terminal equipment at Kelly and/or Tecumseh to increase the rating of the 161kV line between the two substations to a summer emergency rating of 151 MVA.	$1,550,993	WR	1/1/2021
Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161kV line between the two substations to a summer emergency rating of 243 MVA.	$114,154	WR/EDE	1/1/2020

Reference Case Portfolio



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Reference Case Portfolio - Reliability

General Description	Cost Estimate	Location (Zone)	Staging Year
Install 28.8-MVAR capacitor bank at Port Robson 138 kV	$2,306,250	AEP	6/1/2025
Install 28.8-MVAR capacitor bank at IPC 138 kV*	$1,270,836	AEP	1/1/2020
Tap the existing 230kV line from Hobbs to Yoakum and the existing 115kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115kV transformer at new Hobbs - Yoakum Tap substation.	$9,953,077	SPS	6/1/2020

* - Zonal Reliability Project

Reference Case Portfolio - Economic

General Description	Cost Estimate	Location (Zone)	Staging Year
Rebuild 11.2-mile 138kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	$17,015,000	AEP	1/1/2022
Add 1 ohm Series reactor to Northeast - Charlotte 161 kV line	$512,500	KCPL	1/1/2020
Install one (1) 138kV phase shifting transformer at Woodward EHV along with upgrading relay, protective, and metering equipment, and all associated and miscellaneous materials.	$7,459,438	OGE	1/1/2020
Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115kV line between the two substations to a summer emergency rating of 175 MVA.	$969,942	SPS	1/1/2020
Tap the intersection of the 230kV line from Tolk to Yoakum and the 115kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115kV transformer at new substation.	$11,961,951	SPS	1/1/2020
Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	$7,423,880	SPS	1/1/2024
Rebuild 7.12-mile 115kV transmission line from Hereford to DS#6 and upgrade any necessary equipment to increase the summer emergency rating to 240 MVA.	$3,359,671	SPS	1/1/2020
Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138kV line between the two substations to a summer emergency rating of 110 MVA.	$244,606	WR	1/1/2020
Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161kV line between the two substations to a summer emergency rating of 243 MVA.	$114,154	WR/EDE	1/1/2020


SPP
75th Anniversary
75
SEVENTY-FIVE YEARS OF
RELIABILITY THROUGH RELATIONSHIPS

2017 ITP10 Additional Analysis

November 15-17th, 2016

ESWG/TWG

SPP Staff

Developing a Recommended Plan

- NTC Recommendations of F1/F2 and F3 Reference Case Projects
- "Side-Bar" Analysis
- Alternative Project Analysis

Schedule

- ESWG and TWG
  - November 15-17
- TWG
  - December 7
  - December 14
- ESWG
  - December 8

NTC Recommendations of F1/F2 and F3 Reference Case Projects

NTC Recommendations of F1/F2 and F3 Reference Case Projects

- No regret NTCs would be to only recommend projects identified in both F1/F2 and F3 Reference Case Portfolios
  - Not preferred based upon review of projects that would not be recommended
- Alternative method would be to also recommend NTCs for projects that are either part of the F1/F2 or F3 Reference Case portfolios
  - SPP Staff will provide justification narratives

Additional Staging Analysis

- Recommend which projects should have a different RTO determined need date than the F1/F2 Case and F3 Reference Case staging dates
  - Use existing RTO Need Dates from 2016 ITPNT and Generation Interconnection as applicable
  - Use extrapolation combined with SPP staff justification for accelerated RTO determined need dates for projects that can be placed in-service prior to 2020 staging year
  - Identify and analyze staging impact of specific step change drivers as applicable
- SPP staff recommends using a combination of these as applicable with justifications documented

F1/F2 Case/F3 Reference Case Project Similarities

General Description	Cost Estimate ($M)	F3 Ref Staging Date	F1/F2 Staging Date	Extrapolated Staging Year	Existing RTO Need Date	Comment
Install 28.8-MVAR capacitor bank at Port Robson 138 kV	$2.3	6/2025	6/2025	-	-	Stage based on step change driver
Tap the existing 230kV line from Hobbs to Yoakum and the existing 115kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115kV transformer at new Hobbs - Yoakum Tap substation.	$10.0	6/2020	1/2020	-	6/2017	
Rebuild 11.2-mile 138kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	$17.0	1/2022	1/2023	-	-	Stage based on step change driver
Install one (1) 138kV phase shifting transformer at Woodward EHV along with upgrading relay, protective, and metering equipment, and all associated and miscellaneous materials.	$7.6	1/2020	1/2020	2017	6/2017	
Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115kV line between the two substations to a summer emergency rating of 175 MVA.	$1.0	1/2020	1/2020	2017	-	Accelerate Need Date
Tap the intersection of the 230kV line from Tolk to Yoakum and the 115kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115kV transformer at new substation.	$12.0	1/2020	1/2020	2017	6/2018	
Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	$7.4	1/2024	1/2020	-	6/2017	
Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138kV line between the two substations to a summer emergency rating of 110 MVA.	$0.2	1/2020	1/2020	2017	-	Accelerate Need Date
Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161kV line between the two substations to a summer emergency rating of 243 MVA.	$0.1	1/2020	1/2020	2017	-	Accelerate Need Date

F1/F2 Case/F3 Reference Case Project Differences

Portfolio	General Description	Cost Estimate ($M)	Staging Date	Extrapolated Staging Year	Comment
F1/F2	Double circuit 115 kV line from Magic City to a point on the Logan - Mallard 115 kV line.	$3.1	1/2021	-	Related Needs identified in CSP study with MISO
F1/F2	Second 230 kV line from Knoll to Post Rock.	$3.4	1/2020	2017	Recommend project and Accelerate (preliminary)
F1/F2	345/161 kV transformer at Morgan substation	$8.7	1/2020	2017	Negative benefit in Ref Case - Related to Chronic Operation/RCAR/Seams Issue- Alternative Project Recommendation
F1/F2	Capacitor Banks at Atwood 115kV Seguin Tap 115kV substations.	$2.4	6/2024	-	Investigate drivers
F1/F2	Lawrence - Sioux Falls 115kV rebuild	$1.4	1/2021	-	Need identified in CSP study with MISO
F1/F2	Siloam Springs (AEP)-Siloam Springs City (GRDA) 161kV rebuild.	$5.2	1/2020	2017	Recommend project and Accelerate (preliminary)
F1/F2	Knox Lee to South Texas Eastman 138kV rebuild.	$8.5	6/2022	-	Invalidate need based on "Side-Bar"
F1/F2	New sub on the Nichols to Grapevine 230kV line and new line from new sub to Martin.	$15.0	1/2020	-	Evaluate project alternatives as economic projects based on "Side-Bar"
F1/F2	Kelly and/or Tecumseh terminal upgrades.	$1.6	1/2021	-	Recommend project (preliminary)
F1/F2	Tupelo, Tupelo Tap and Lula terminal upgrades.	$0.1	1/2020	2017	Recommend project and Accelerate (preliminary)
F3 Ref Case	Install 28.8-MVAR capacitor bank at IPC 138 kV-Zonal Reliability Project	$1.3	1/2020	-	Investigate drivers
F3 Ref Case	Hereford to DS#6 115kV rebuild.	$3.6	1/2020	2017	Related to Chronic Operation Issue - Alternative Project Recommendation
Both	Series reactor on Northeast - Charlotte 161 kV line	$0.5	1/2020	2018	Recommend appropriate reactor size and Accelerate

“Side-Bar” Analysis

"Side-Bar" Analysis

- SPP is currently performing additional analysis to help inform project recommendations due to schedule differences with NT studies
- Analysis
  - Inclusion of all known model corrections and NTC projects in base model
  - Additional economic model changes to support improvements
  - Restart process at constraint assessment
- Status
  - Current: Performing Economic and Reliability Assessment and comparisons
  - Next: Project screening as needed to reaffirm project selection

"Side-Bar" Objectives

- Facilitate recommendation of NTC without regrets
  - Avoid recommending projects for NTC where need no longer exists or where a right size issue exists
  - Avoid recommending reliability projects for NTC where need may be an economic constraint
- Identify modeling and process enhancements
  - Economic model changes
    - Removed external transactions between external translated and non-translated regions
    - Manitoba Hydro DC Tie modeling
    - SWPA and WAPA transaction replacement with pro rata %ownership of fleet
  - DC-AC changes using PROMOD calculated losses to reduce discrepancy between DC and AC transmission line loadings

"Side-Bar" Preliminary Results

- Avoid recommending reliability projects for NTC where need may be an economic constraint

General Description	Cost Estimate	Posted Staging Date
Rebuild 5.5-mile 138kV line from Knox Lee to South Texas Eastman and upgrade any necessary equipment to increase the branch ratings to 371/470 MVA.	$8,456,250	6/1/2022

- Thermal reliability need modeled as an economic model constraint
  - Annual Congestion Score: F1=$4,496, F2=$4,565, F3=$246
- SPP staff recommends invalidating need based economic need criteria being constraints with greater than $50,000 in annual congestion score

General Description	Cost Estimate	Posted Staging Date
Tap the Nichols to Grapevine 230kV line to construct new substation. Install a new 230/115kV transformer at Nichols - Grapevine tab substation. Construct new 2-mile 115kV line from Martin to Nichols/Grapevine tap substation. Install terminal upgrades at Martin to accommodate new 115kV line from the Nichols/Grapevine tap substation.	$14,936,215	1/1/2020

- Thermal reliability need modeled as an economic model constraint
  - Annual Congestion Score: F1=$86,922, F2=$80,057, F3=$55,924
- SPP staff recommends applying economic project selection, consolidation, and staging criteria to need

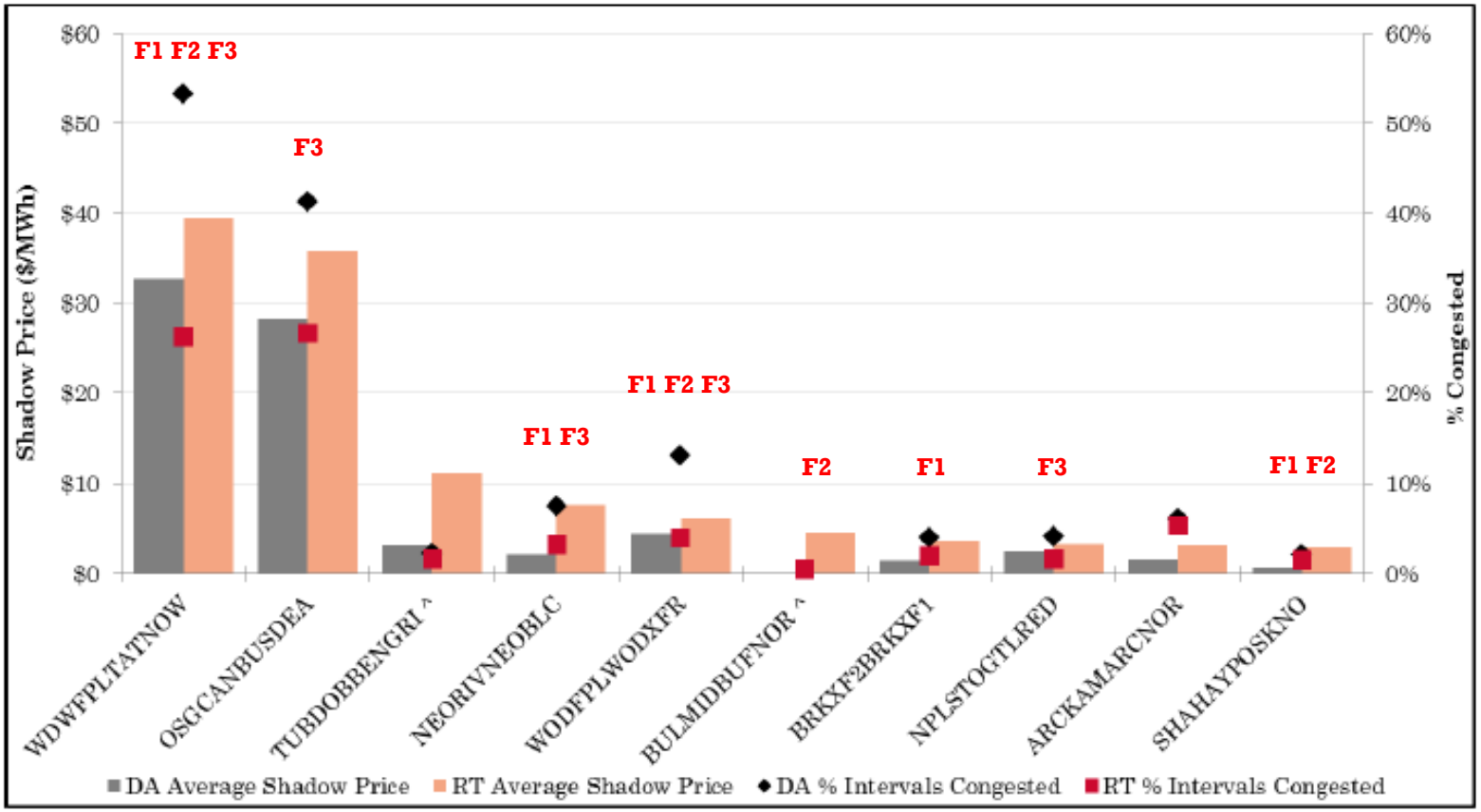
Wind Profiles Background

- It was recently discovered that the 2017 ITP10 wind hourly profiles are using Coordinated Universal Time (UTC), rather than the local time zone for the wind profile
  - Hourly profiles are offset 6-7 hours for the full year
- Staff adjusted the wind profiles to local time for all 3 futures, ran PROMOD, and compared outputs to the ITP10 models
  - Looked at economic needs, 8760 unit output differences, and peak and off-peak hour SCUC differences
- Staff evaluation showed no impacts to be expected for reliability or economic project selection due to the change in wind profiles
  - A comparison of economic needs is included in the Appendix
- We are applying the wind profile modification to the sidebar analysis, in which selected projects will be tested to see if they continue to show benefit in light of model updates
  - The sidebar models will also be used in the Alternative Project Analysis

Alternative Project Analysis

2015 State of the Market Report
Top 10 Flowgates – ITP Correlation

Figure 5–5 SPP Congestion by Shadow Price, 2015



% Intervals Congested includes both breached and binding intervals

*Future specific ITP10 need correlation in red text above each flowgate

Alternative Project Analysis

- Certain transmission issues identified under scope and out of scope criteria were posted for informational purposes
- This was done to allow for submittal and further evaluation of projects that may support SPP initiatives
  - RCAR II
  - Seams
  - Operational issues
- Current target areas for alternative project recommendations
  - Eastern Seams
    - Southeast Kansas – Southwest Missouri
    - Northeast Oklahoma – Northwest Arkansas
  - Texas Panhandle
    - SPS North to South

Eastern Seams - Background

- Loading in NW Arkansas and SW Missouri, high exports, and limited hydro and Springfield generation can lead to these constraints becoming congested.

- Southeast Kansas – Southwest Missouri needs
  - Neosho - Riverton 161kV FLO
    Neosho – Blackberry 345kV - F1, F3
  - Brookline 345/161kV Xfmr #1 FLO Brookline 345/161kV Xfmr #2 – F1, F3
  - Butler - Altoona 138kV FLO
    Neosho – Caney River 345kV F1, F2, F3

- Northeast Oklahoma-Northwest Arkansas needs
  - Siloam City-Siloam Springs161kV FLO Flint Creek-Tonnece 7 345kV - F1, F2
  - Bull Shoals - Midway Jordan161kV FLO Bull Shoals - Buford161kV - F2
  - Highway 59 – VBI North161kV FLO
    Fort Smith – Muskogee 345kV - F2 - Model Correction

Alternative project analysis for Brookline Transformer

- Alternative for Brookline 345/161kV Xfmr #1 FLO Brookline 345/161kV Xfmr #2 need identified as an Economic Need in Future 1 and a Reliability Need related to an Economic Constraint in Future 3
  - F1/F2 portfolio project to add a Morgan 345/161 kV transformer has poor performance in Future 3
- Additional economic project screening with manual events
- Economic Sensitivities of top alternatives
  - Hydro Generation Dispatch Sensitivity Impact
- Reliability Sensitivities of top alternatives
  - Reliability Metrics
  - AC contingency analysis runs and comparisons including 69 kV (<100% thermal and >0.90 voltage monitoring)

Texas Panhandle - Background

- The Texas Panhandle corridor relies mainly on 230 kV transmission lines between Amarillo and Lubbock, TX. The transmission corridor is impacted by the predominantly gas-fired generation in the south that is more expensive than wind generation to the north.

- NTCs in progress

Study	Upgrade Name	RTO Determined Need Date	In Service Date	Upgrade Estimated Cost Amount
ATSS	Canyon East Sub - Randall County Interchange 115 kV Ckt 1 Rebuild	2/2014	1/2021	$12,806,065.00
ATSS	Canyon East Sub - Canyon West Sub 115 kV Ckt 1 Rebuild	2/2014	1/2018	$4,991,564.00
2015 ITPNT	Canyon West - Dawn 115 kV Ckt 1 Rebuild *	6/2017	1/2019	$9,756,809.00
2015 ITPNT	Dawn - Panda 115 kV Ckt 1 Rebuild*	6/2017	1/2019	$5,901,274.00
2015 ITPNT	Deaf Smith - Panda 115 kV Ckt 1 Rebuild*	6/2017	1/2019	$3,501,534.00
2016 ITPNT	Canyon East Tap - Randall 115 kV Ckt 1 Rebuild*	6/2017	1/2020	$4,804,292.00
				$41,761,538.00

- After reviewing expenditures to date and alternative project relief the *Avoided Reliability Upgrades 9.8+5.9+3.5+4.8 = $24 million

- Preliminary avoided prospective reliability upgrades = $41 million from Future 3 - Hereford-DS #6 115kV FLO Deaf Smith PLX Tap – Plant X6 230kV which may be indicative of rebuilding another 55.7 miles of 115 kV line

- SPS North to South Stability Interface

Texas Panhandle - Uncertainties

- ITP Resource plans and siting to date have reduced the congestion on the constraints for ITP10
- 2017 ITP10 Resource Plan
  - 550 MW of steam gas retirements in South SPS – 220 MW in North SPS
  - F1,F2, and F3 – 4 550 MW CCs in South SPS
  - F3 - 2 additional 216 MW CT
  - F3 includes Solar and Wind South of interface
  - F1 and F2 includes additional Solar and Wind South of interface
- New Mexico Coops and Lea County are transitioning to Western Farmers as the LRE
  - 1-550 MW CC sited in South SPS
- Potential Clean Line integration
- Generation fleet modifications in area
- What best facilitates generation interconnection and transmission service processes as well as maintaining reliability and promoting transmission investment with regional economic benefits?
- Potter to Tolk 345 kV ($147 million) included in 2010 ITP20 and 2013 ITP20

Texas Panhandle - Analysis

- Potter to Tolk 345 kV alternative
- Economic analysis to include avoided reliability upgrades and prospective reliability upgrades
- Economic Sensitivities
  - Move 1 CC at Deaf Smith to a 2035 RCAR II site in SPS North
  - Move 1 CC at Deaf Smith and retire Tolk 1 with CC replacement
  - Move 1 CC at Deaf Smith and convert 1 CC to 3 CTs at Hobbs
  - Each requires changes to generator outlet facilities, NTC removal, and event file
- Reliability Sensitivities
  - FCITC Sensitivities to identify prospective reliability needs/projects that can be avoided with economic project alternative
  - Final Reliability Assessment

Texas Panhandle - Preliminary Results

- **Potter-Tolk 345 kV** *Avoided NTC projects **Preliminary Avoided Prospective NTC projects
  - 2017 ITP10 Economic model

Future	SPP Benefit	SPP B/C
F1	$7.0M	0.3 / 0.4* / 0.5**
F2	$7.7M	0.3 / 0.4* / 0.6**
F3	$12.9M	0.5 / 0.6* / 0.9**

  - Move 1 CC at Deaf Smith to Moore County a 2035 RCAR II site in SPS North

Future	SPP Benefit	SPP B/C
F1*	$19.8M	0.7 / 0.8* / 1.2**
F3*	$30.0M	1.0 / 1.2* / 1.8**

  - Move 1 CC at Deaf Smith and retire Tolk 1 with CC replacement

Future	SPP Benefit	SPP B/C
F1*	$13.5M	0.4 / 0.5* / 0.8**
F3*	$41.6M	1.4 / 1.6* / 2.4**

  - Move 1 CC at Deaf Smith and convert 1 CC at Hobbs to 3 CTs

Future	SPP Benefit	SPP B/C
F1*	$23.4M	0.8 / 0.9* / 1.4**
F3*	$36.9M	1.2 / 1.4* / 2.2**

* Includes respective consolidated portfolio

Appendix

Wind Profile Modification – F1 Economic Needs Comparison

F1 Constraints	Existing ITP10 model		Wind Profile Update		Congestion Score Diff	Congestion Score Diff %
	Rank	Congestion Score	Rank	Congestion Score		
B:652216WATFORD4 652408WATFORD7 1 FLO BASE CASE	1	781,727	1	778,264	3,464	0.4%
B:661008BEULAH 7 661018COYOTE 7 1 FLO CENTER 4-MANDAN 4 230[1]	2	675,574	2	680,072	(4,499)	-0.7%
B:620327HANKSON4 620329WAHPETN4 1 FLO BUFFALO3-JAMESTN3 345[1]	3	538,715	3	547,124	(8,410)	-1.6%
B:526076STANTON_W 3526146INDIANA 31 FLO TUCO_INT 6-CARLISLE 6 23	4	464,889	4	517,127	(52,237)	-11.2%
B:615347GRE-MCHENRY4615348GRE-MCHENRY71 FLO BASE CASE	5	408,953	5	401,089	7,864	1.9%
B:532987BUTLER 4 533001ALTOONA4 1 FLO CANEYRV7-NEOSHO 7 345[1]	6	257,440	6	308,760	(51,320)	-19.9%
B:652508S3 7 652551GRANITF7 1 FLO LYON CO 3-LYON CO7 115[9	7	247,828	7	243,591	4,238	1.7%
B:507755S SHV 4 507765WALLAKE4 1 FLO FTHUMBG4-TRICHEL4138[1](	8	194,151	-	186,666	7,484	3.9%
B:507755S SHV 4 507765WALLAKE4 1 FLO DOLHILL6-DOLHILL7 345[1]	-	176,644	8	198,685	(22,041)	-12.5%
B:602003BLUEETA5 631043WINBAGO5 1 FLO WILMART3-FIELD_N3 345[1]	9	188,723	10	176,865	11,858	6.3%
B:530693VINETAP3 530581N HAYS3 1 FLO KNOLL 6-POSTROCK6 230[1]	10	179,921	9	183,645	(3,725)	-2.1%
B:532913KELLY 5 532920TECHILL5 1 FLO KELLY5-KELLY3 115[1](WER	11	157,061	14	143,538	13,523	8.6%
B:505600TUPELO 4 521071TUPLOTP4 1 FLO PITTSB-7-SEMINOL7 345[1]	12	154,155	11	159,492	(5,336)	-3.5%
B:615348GRE-MCHENRY7659113VOLTAIR7 1 FLO GRE-BALTA4-RUGBY4 230[1]	13	149,860	13	156,967	(7,106)	-4.7%
B:514785WOODWRD4 515785WINDFRM4 1 FLO WODWRD 269-WOODWRD4 138[	14	138,491	12	158,794	(20,303)	-14.7%
I:FTCAL_S FLO BASE CASE	15	132,450	15	133,100	(651)	-0.5%
B:532937NEOSHO 5 547469RIV4525 1 FLO 7BLACKBERRY-NEOSHO 7 345	16	115,799	17	119,038	(3,239)	-2.8%
B:542985NEAST 5 543133CHARLOT5 1 FLO NEAST5-GRAND W5 161[1](K	17	99,579	18	90,374	9,204	9.2%
B:526434SUNDOWN 3526435SUNDOWN 61 FLO LAMB_CNTY3-HOCKLEY3 115[	18	94,603	16	124,743	(30,139)	-31.9%
B:527275SEMINOLE 3527276SEMINOLE 62 FLO SEMINOLE 6 XFR 230/115[1	19	90,904	19	88,107	2,797	3.1%
B:506948SILOAM 5 512643SILMCTY5 1 FLO FLINTCR7-TONECE7 345[1](	20	76,650	21	77,933	(1,283)	-1.7%
B:527036SHELL_C2 3527136DENVER_S 31 FLO LE-WEST_SUB3-LE-LOVINTON	21	75,257	22	74,685	572	0.8%
B:549984BROOKLINE 7549969BROOKLINE 51 FLO BROOKLINE7-BROOKLINE5 16	22	74,465	20	87,490	(13,025)	-17.5%
B:652524SIOUXFL7 603012LAWRENC7 1 FLO SPLT RK4-SIOUXFL4 230[1]	23	70,107	23	65,302	4,805	6.9%
B:608740GR RPDS7 618009GRE-POKEGMT71 FLO FORBES 2 500-CHIS-N 2 50	24	62,701	24	56,678	6,023	9.6%
B:530592SMOKYHL6 532873SUMMIT 6 1 FLO CIRCLE 6-GRTBEND6 230[1]	-	47,107	25	54,055	(6,948)	-14.7%

Wind Profile Modification – F2 Economic Needs Comparison

F2 Constraints	Existing ITP10 model		Wind Profile Update		Congestion Score Diff	Congestion Score Diff %
	Rank	Congestion Score	Rank	Congestion Score		
B:526076STANTON_W 3526146INDIANA 31 FLO TUCO_INT 6-CARLISLE 6 23	1	662,310	1	710,582	(48,272)	-7.3%
B:615347GRE-MCHENRY4615348GRE-MCHENRY71 FLO BASE CASE	2	597,138	2	601,276	(4,137)	-0.7%
B:652216WATFORD4 652408WATFORD7 1 FLO BASE CASE	3	536,225	3	530,150	6,075	1.1%
B:652508S3 7 652551GRANITF7 1 FLO LYON CO 3-LYON CO7 115[9	4	371,481	4	375,649	(4,168)	-1.1%
B:602003BLUEETA5 631043WINBAGO5 1 FLO WILMART3-FIELD_N3 345[1]	5	300,035	5	312,862	(12,827)	-4.3%
B:661008BEULAH 7 661018COYOTE 7 1 FLO CENTER 4-MANDAN 4 230[1]	6	293,122	6	285,343	7,779	2.7%
B:507755S SHV 4 507765WALLAKE4 1 FLO FTHUMBG4-TRICHEL4138[1](	7	218,942	-	201,737	17,206	7.9%
B:507755S SHV 4 507765WALLAKE4 1 FLO DOLHILL6-DOLHILL7 345[1]	-	208,736	7	222,713	(13,977)	-6.7%
B:615348GRE-MCHENRY7659113VOLTAIR7 1 FLO GRE-BALTA4-RUGBY4 230[1]	8	149,813	8	148,311	1,503	1.0%
B:530693VINETAP3 530581N HAYS3 1 FLO KNOLL 6-POSTROCK6 230[1]	9	134,509	10	141,473	(6,964)	-5.2%
B:532987BUTLER 4 533001ALTOONA4 1 FLO CANEYRV7-NEOSHO 7 345[1]	10	128,073	9	143,621	(15,547)	-12.1%
B:520510NAPLESTP 520867CORN TP4 1 FLO SUNNYSD7-G14-057T 345[1]	11	125,364	11	136,481	(11,117)	-8.9%
B:514785WOODWRD4 515785WINDFRM4 1 FLO WODWRD 269-WOODWRD4 138[	12	110,046	13	127,951	(17,905)	-16.3%
B:3388135MIDWY JRDN#505460BULL SH5 1 FLO BUFORD5-BULL SH5 161[1](	13	96,338	14	119,920	(23,582)	-24.5%
I:FTCAL_S FLO BASE CASE	14	85,756	15	83,096	2,660	3.1%
B:505600TUPELO 4 521071TUPLOTP4 1 FLO PITTSB-7-SEMINOL7 345[1]	15	81,181	17	75,991	5,190	6.4%
B:527275SEMINOLE 3527276SEMINOLE 62 FLO SEMINOLE 6 XFR 230/115[1	16	79,960	19	67,580	12,380	15.5%
B:542985NEAST 5 543133CHARLOT5 1 FLO NEAST5-GRAND W5 161[1](K	17	79,745	20	62,402	17,343	21.7%
B:526434SUNDOWN 3526435SUNDOWN 61 FLO LAMB_CNTY3-HOCKLEY3 115[	18	79,392	12	129,385	(49,992)	-63.0%
B:652524SIOUXFL7 603012LAWRENC7 1 FLO SPLT RK4-SIOUXFL4 230[1]	19	79,374	16	78,054	1,320	1.7%
B:515339VBI 5 515347HWY59 5 1 FLO MUSKOGE7-FTSMITH7 345[1]	20	71,172	18	68,022	3,150	4.4%
B:530592SMOKYHL6 532873SUMMIT 6 1 FLO POSTROCK7-AXTELL 3 345[1	21	58,462	23	50,959	7,503	12.8%
B:506948SILOAM 5 512643SILMCTY5 1 FLO FLINTCR7-TONECE7 345[1](	22	50,011	21	52,373	(2,362)	-4.7%
B:527036SHELL_C2 3527136DENVER_S 31 FLO LE-WEST_SUB3-LE-LOVINTON	-	49,076	22	51,218	(2,142)	-4.4%

Wind Profile Modification – F3 Economic Needs Comparison

F3 Constraints	Existing ITP10 model		Wind Profile Update		Congestion Score Diff	Congestion Score Diff %
	Rank	Congestion Score	Rank	Congestion Score		
B:652216WATFORD4 652408WATFORD7 1 FLO BASE CASE	1	821,749	1	817,813	3,936	0.5%
B:615650GRE-CHUBLAK7616929GRE-KENRICK71 FLO HELENA 3-SCOTTCO3 345[1]	2	635,398	2	612,685	22,713	3.6%
B:526076STANTON_W 3526146INDIANA 31 FLO TUCO_INT 6-CARLISLE 6 23	3	379,447	3	441,490	(62,044)	-16.4%
B:507755S SHV 4 507765WALLAKE4 1 FLO FTHUMBG4-TRICHEL4138[1](	4	274,213	4	283,175	(8,963)	-3.3%
B:652508S3 7 652551GRANITF7 1 FLO LYON CO 3-LYON CO7 115[9	5	221,315	5	219,886	1,429	0.6%
B:532987BUTLER 4 533001ALTOONA4 1 FLO CANEYRV7-NEOSHO 7 345[1]	6	166,526	6	175,719	(9,193)	-5.5%
B:514785WOODWRD4 515785WINDFRM4 1 FLO WODWRD 269-WOODWRD4 138[	7	109,243	8	115,678	(6,435)	-5.9%
B:532937NEOSHO 5 547469RIV4525 1 FLO 7BLACKBERRY-NEOSHO 7 345	8	103,326	9	100,159	3,167	3.1%
B:524606HEREFORD 3524629DS-#6 31 FLO DF PLX TP6-PLANT_X6 230[	9	94,461	10	93,853	608	0.6%
B:526434SUNDOWN 3526435SUNDOWN 61 FLO LAMB_CNTY3-HOCKLEY3 115[	10	92,582	7	138,894	(46,312)	-50.0%
B:520510NAPLESTP 520867CORN TP4 1 FLO SUNNYSD7-G14-057T 345[1]	11	88,668	12	83,704	4,965	5.6%
B:527275SEMINOLE 3527276SEMINOLE 62 FLO SEMINOLE 6 XFR 230/115[1	12	87,371	11	84,289	3,082	3.5%
B:542985NEAST 5 543133CHARLOT5 1 FLO NEAST5-GRAND W5 161[1](K	13	82,395	13	70,601	11,793	14.3%
B:505600TUPELO 4 521071TUPLOTP4 1 FLO PITTSB-7-VALIANT7 345[1]	14	57,979	14	57,644	335	0.6%
I:REDWILLMINGO FLO BASE CASE	15	53,504	-	46,508	6,996	13.1%
B:652515HURON 7 660009BTAP WP7 1 FLO FTTHOMP4-LETCHER4 230[1]	16	52,591	-	47,481	5,110	9.7%
B:640338SCOTBLF7 640397VICTRYH7 1 FLO STEGALL4-STGXFMR4 230[1]	17	52,309	15	52,981	(672)	-1.3%
B:530693VINETAP3 530581N HAYS3 1 FLO KNOLL 6-POSTROCK6 230[1]	-	40,829	16	50,755	(9,926)	-24.3%

Economic Needs – New or Dropped Out

- F1 Summit - Smoky Hills would be new need
  - Low congestion score would be similar to the congestion score in F2 (for which this is a need in the original). No project was identified for this need in F2; therefore, no project for this need would be expected in F1.
- F2 Shell - Denver would be new need
  - There is a reliability voltage project in all 3 futures that addresses this need. This reliability voltage project would not drop out with the wind profile update
- F3 Vine Tap - N. Hays would be new need
  - This is a more significant need in F1 and F2, and there is a project identified for it in the F1 and F2 portfolios that will address this need
- F3 Red Willow Mingo interface would drop out
  - No project has been identified to address this need
- F3 Huron - Btap would drop out
  - No project has been identified to address this need

2017 ITP10 Wind Profiles

ESWG

11/17/16

Background

- A member recently pointed out that the 2017 ITP10 wind profiles based on NREL data were not adjusted for local time
  - The profiles currently use UTC (London) time
  - Wind profiles in CST are 6 hours off
  - Wind profiles in MST are 7 hours off
- We adjusted the wind profiles to local time for all 3 futures, ran PROMOD, and compared outputs to the original cases
  - Compared economic needs, 8760 unit output differences, and peak and off peak hour SCUC differences
  - We wanted to present these details, explain additional steps we plan to take, and get stakeholder feedback

Future 1 Economic Needs – Comparison

F1 Constraints	Existing ITP10 model		Wind Profile Update		Congestion Score Diff	Congestion Score Diff %
	Rank	Congestion Score	Rank	Congestion Score		
B:652216WATFORD4 652408WATFORD7 1 FLO BASE CASE	1	781,727	1	778,264	3,464	0.4%
B:661008BEULAH 7 661018COYOTE 7 1 FLO CENTER 4-MANDAN 4 230[1]	2	675,574	2	680,072	(4,499)	-0.7%
B:620327HANKSON4 620329WAHPETN4 1 FLO BUFFALO3-JAMESTN3 345[1]	3	538,715	3	547,124	(8,410)	-1.6%
B:526076STANTON_W 3526146INDIANA 31 FLO TUCO_INT 6-CARLISLE 6 23	4	464,889	4	517,127	(52,237)	-11.2%
B:615347GRE-MCHENRY4615348GRE-MCHENRY71 FLO BASE CASE	5	408,953	5	401,089	7,864	1.9%
B:532987BUTLER 4 533001ALTOONA4 1 FLO CANEYRV7-NEOSHO 7 345[1]	6	257,440	6	308,760	(51,320)	-19.9%
B:652508S3 7 652551GRANITF7 1 FLO LYON CO 3-LYON CO7 115[9	7	247,828	7	243,591	4,238	1.7%
B:507755S SHV 4 507765WALLAKE4 1 FLO FTHUMBG4-TRICHEL4138[1](	8	194,151	-	186,666	7,484	3.9%
B:507755S SHV 4 507765WALLAKE4 1 FLO DOLHILL6-DOLHILL7 345[1]	-	176,644	8	198,685	(22,041)	-12.5%
B:602003BLUEETA5 631043WINBAGO5 1 FLO WILMART3-FIELD_N3 345[1]	9	188,723	10	176,865	11,858	6.3%
B:530693VINETAP3 530581N HAYS3 1 FLO KNOLL 6-POSTROCK6 230[1]	10	179,921	9	183,645	(3,725)	-2.1%
B:532913KELLY 5 532920TECHILL5 1 FLO KELLY5-KELLY3 115[1](WER	11	157,061	14	143,538	13,523	8.6%
B:505600TUPELO 4 521071TUPLOTP4 1 FLO PITTSB-7-SEMINOL7 345[1]	12	154,155	11	159,492	(5,336)	-3.5%
B:615348GRE-MCHENRY7659113VOLTAIR7 1 FLO GRE-BALTA4-RUGBY4 230[1]	13	149,860	13	156,967	(7,106)	-4.7%
B:514785WOODWRD4 515785WINDFRM4 1 FLO WODWRD 269-WOODWRD4 138[	14	138,491	12	158,794	(20,303)	-14.7%
I:FTCAL_S FLO BASE CASE	15	132,450	15	133,100	(651)	-0.5%
B:532937NEOSHO 5 547469RIV4525 1 FLO 7BLACKBERRY-NEOSHO 7 345	16	115,799	17	119,038	(3,239)	-2.8%
B:542985NEAST 5 543133CHARLOT5 1 FLO NEAST5-GRAND W5 161[1](K	17	99,579	18	90,374	9,204	9.2%
B:526434SUNDOWN 3526435SUNDOWN 61 FLO LAMB_CNTY3-HOCKLEY3 115[	18	94,603	16	124,743	(30,139)	-31.9%
B:527275SEMINOLE 3527276SEMINOLE 62 FLO SEMINOLE 6 XFR 230/115[1	19	90,904	19	88,107	2,797	3.1%
B:506948SILOAM 5 512643SILMCTY5 1 FLO FLINTCR7-TONECE7 345[1](	20	76,650	21	77,933	(1,283)	-1.7%
B:527036SHELL_C2 3527136DENVER_S 31 FLO LE-WEST_SUB3-LE-LOVINTON	21	75,257	22	74,685	572	0.8%
B:549984BROOKLINE 7549969BROOKLINE 51 FLO BROOKLINE7-BROOKLINE5 16	22	74,465	20	87,490	(13,025)	-17.5%
B:652524SIOUXFL7 603012LAWRENC7 1 FLO SPLT RK4-SIOUXFL4 230[1]	23	70,107	23	65,302	4,805	6.9%
B:608740GR RPDS7 618009GRE-POKEGMT71 FLO FORBES 2 500-CHIS-N 2 50	24	62,701	24	56,678	6,023	9.6%
B:530592SMOKYHL6 532873SUMMIT 6 1 FLO CIRCLE 6-GRTBEND6 230[1]	-	47,107	25	54,055	(6,948)	-14.7%

Future 2 Economic Needs – Comparison

F2 Constraints	Existing ITP10 model		Wind Profile Update		Congestion Score Diff	Congestion Score Diff %
	Rank	Congestion Score	Rank	Congestion Score		
B:526076STANTON_W 3526146INDIANA 31 FLO TUCO_INT 6-CARLISLE 6 23	1	662,310	1	710,582	(48,272)	-7.3%
B:615347GRE-MCHENRY4615348GRE-MCHENRY71 FLO BASE CASE	2	597,138	2	601,276	(4,137)	-0.7%
B:652216WATFORD4 652408WATFORD7 1 FLO BASE CASE	3	536,225	3	530,150	6,075	1.1%
B:652508S3 7 652551GRANITF7 1 FLO LYON CO 3-LYON CO7 115[9	4	371,481	4	375,649	(4,168)	-1.1%
B:602003BLUEETA5 631043WINBAGO5 1 FLO WILMART3-FIELD_N3 345[1]	5	300,035	5	312,862	(12,827)	-4.3%
B:661008BEULAH 7 661018COYOTE 7 1 FLO CENTER 4-MANDAN 4 230[1]	6	293,122	6	285,343	7,779	2.7%
B:507755S SHV 4 507765WALLAKE4 1 FLO FTHUMBG4-TRICHEL4138[1](	7	218,942	-	201,737	17,206	7.9%
B:507755S SHV 4 507765WALLAKE4 1 FLO DOLHILL6-DOLHILL7 345[1]	-	208,736	7	222,713	(13,977)	-6.7%
B:615348GRE-MCHENRY7659113VOLTAIR7 1 FLO GRE-BALTA4-RUGBY4 230[1]	8	149,813	8	148,311	1,503	1.0%
B:530693VINETAP3 530581N HAYS3 1 FLO KNOLL 6-POSTROCK6 230[1]	9	134,509	10	141,473	(6,964)	-5.2%
B:532987BUTLER 4 533001ALTOONA4 1 FLO CANEYRV7-NEOSHO 7 345[1]	10	128,073	9	143,621	(15,547)	-12.1%
B:520510NAPLESTP 520867CORN TP4 1 FLO SUNNYSD7-G14-057T 345[1]	11	125,364	11	136,481	(11,117)	-8.9%
B:514785WOODWRD4 515785WINDFRM4 1 FLO WODWRD 269-WOODWRD4 138[	12	110,046	13	127,951	(17,905)	-16.3%
B:3388135MIDWY JRDN#505460BULL SH5 1 FLO BUFORD5-BULL SH5 161[1](	13	96,338	14	119,920	(23,582)	-24.5%
I:FTCAL_S FLO BASE CASE	14	85,756	15	83,096	2,660	3.1%
B:505600TUPELO 4 521071TUPLOTP4 1 FLO PITTSB-7-SEMINOL7 345[1]	15	81,181	17	75,991	5,190	6.4%
B:527275SEMINOLE 3527276SEMINOLE 62 FLO SEMINOLE 6 XFR 230/115[1	16	79,960	19	67,580	12,380	15.5%
B:542985NEAST 5 543133CHARLOT5 1 FLO NEAST5-GRAND W5 161[1](K	17	79,745	20	62,402	17,343	21.7%
B:526434SUNDOWN 3526435SUNDOWN 61 FLO LAMB_CNTY3-HOCKLEY3 115[	18	79,392	12	129,385	(49,992)	-63.0%
B:652524SIOUXFL7 603012LAWRENC7 1 FLO SPLT RK4-SIOUXFL4 230[1]	19	79,374	16	78,054	1,320	1.7%
B:515339VBI 5 515347HWY59 5 1 FLO MUSKOGE7-FTSMITH7 345[1]	20	71,172	18	68,022	3,150	4.4%
B:530592SMOKYHL6 532873SUMMIT 6 1 FLO POSTROCK7-AXTELL 3 345[1	21	58,462	23	50,959	7,503	12.8%
B:506948SILOAM 5 512643SILMCTY5 1 FLO FLINTCR7-TONECE7 345[1](	22	50,011	21	52,373	(2,362)	-4.7%
B:527036SHELL_C2 3527136DENVER_S 31 FLO LE-WEST_SUB3-LE-LOVINTON	-	49,076	22	51,218	(2,142)	-4.4%

Future 3 Economic Needs – Comparison

F3 Constraints	Existing ITP10 model		Wind Profile Update		Congestion Score Diff	Congestion Score Diff %
	Rank	Congestion Score	Rank	Congestion Score		
B:652216WATFORD4 652408WATFORD7 1 FLO BASE CASE	1	821,749	1	817,813	3,936	0.5%
B:615650GRE-CHUBLAK7616929GRE-KENRICK71 FLO HELENA 3-SCOTTCO3 345[1]	2	635,398	2	612,685	22,713	3.6%
B:526076STANTON_W 3526146INDIANA 31 FLO TUCO_INT 6-CARLISLE 6 23	3	379,447	3	441,490	(62,044)	-16.4%
B:507755S SHV 4 507765WALLAKE4 1 FLO FTHUMBG4-TRICHEL4138[1](	4	274,213	4	283,175	(8,963)	-3.3%
B:652508S3 7 652551GRANITF7 1 FLO LYON CO 3-LYON CO7 115[9	5	221,315	5	219,886	1,429	0.6%
B:532987BUTLER 4 533001ALTOONA4 1 FLO CANEYRV7-NEOSHO 7 345[1]	6	166,526	6	175,719	(9,193)	-5.5%
B:514785WOODWRD4 515785WINDFRM4 1 FLO WODWRD 269-WOODWRD4 138[	7	109,243	8	115,678	(6,435)	-5.9%
B:532937NEOSHO 5 547469RIV4525 1 FLO 7BLACKBERRY-NEOSHO 7 345	8	103,326	9	100,159	3,167	3.1%
B:524606HEREFORD 3524629DS-#6 31 FLO DF PLX TP6-PLANT_X6 230[	9	94,461	10	93,853	608	0.6%
B:526434SUNDOWN 3526435SUNDOWN 61 FLO LAMB_CNTY3-HOCKLEY3 115[	10	92,582	7	138,894	(46,312)	-50.0%
B:520510NAPLESTP 520867CORN TP4 1 FLO SUNNYSD7-G14-057T 345[1]	11	88,668	12	83,704	4,965	5.6%
B:527275SEMINOLE 3527276SEMINOLE 62 FLO SEMINOLE 6 XFR 230/115[1	12	87,371	11	84,289	3,082	3.5%
B:542985NEAST 5 543133CHARLOT5 1 FLO NEAST5-GRAND W5 161[1](K	13	82,395	13	70,601	11,793	14.3%
B:505600TUPELO 4 521071TUPLOTP4 1 FLO PITTSB-7-VALIANT7 345[1]	14	57,979	14	57,644	335	0.6%
I:REDWILLMINGO FLO BASE CASE	15	53,504	-	46,508	6,996	13.1%
B:652515HURON 7 660009BTAP WP7 1 FLO FTTHOMP4-LETCHER4 230[1]	16	52,591	-	47,481	5,110	9.7%
B:640338SCOTBLF7 640397VICTRYH7 1 FLO STEGALL4-STGXFMR4 230[1]	17	52,309	15	52,981	(672)	-1.3%
B:530693VINETAP3 530581N HAYS3 1 FLO KNOLL 6-POSTROCK6 230[1]	-	40,829	16	50,755	(9,926)	-24.3%

Economic Needs – New or Dropped Out

- F1 Summit - Smoky Hills would be new need
  - Low congestion score would be similar to the congestion score in F2 (for which this is a need in the original). No project was identified for this need in F2; therefore, no project for this need would be expected in F1.
- F2 Shell - Denver would be new need
  - There is a reliability voltage project in all 3 futures that addresses this need. This reliability voltage project would not drop out with the wind profile update (detailed in later slide)
- F3 Vine Tap - N. Hays would be new need
  - This is a more significant need in F1 and F2, and there is a project identified for this in F1 and F2 (Knoll – Post Rock 230 kV second circuit). This is in the CPP consolidated portfolio and not the Reference Case portfolio, but this project will be tested in F3 and the results may have an impact in determining if this project gets recommended for NTC.
- F3 Red Willow Mingo interface would drop out
  - No project identified
- F3 Huron – B Tap would drop out
  - No project identified

Generation Dispatch Comparison – 8760

- Compared annual generator MWh for each future
- There are many minor differences, but nothing that jumps out as game changing

*Output by unit is posted to TrueShare at:

Integrated Transmission Planning – Confidential and Protected Material and or Critical Energy Infrastructure Information-Do Not Release -> 2017 ITP10 -> Output Data -> 20161101_Wind_Profile_Update_8760_Dispatch_Diff.xlsx

Comparison of Reliability Hours

- For all futures:
  - Peak hour:
    - 08/06 @ 1700 in both cases
  - Off-peak hour:
    - 01/04 @ 0500 originally,
    - 10/11 @ 0200 with wind profile modification

Future	Date	Hour	Off-Peak Hour	SPP Load (MW)	Wind (MW)	Wind/Load
F1/F2	1/4/2025	5:00 AM	Original	20,962	14,798	70.6%
F1/F2	10/11/2025	2:00 AM	Modified	23,461	14,799	63.1%
F3	1/4/2025	5:00 AM	Original	20,962	12,879	61.4%
F3	10/11/2025	2:00 AM	Modified	23,461	13,406	57.1%

Reliability Hours – Unit Commitment

- Compared the unit commitment in each of the 6 reliability hours to try to gauge any potential differences in reliability needs/projects
- 4 Reliability Voltage Projects in Consolidated Portfolios
  - Tap Yoakum - Hobbs 230 kV and Allred - Lea County Waits 115 kV line at intersection, New Sub, New 230/115kV transformer (SPS)
  - Install 28.8 MVAR cap bank at Atwood and 14.4 MVAR cap bank at Sequin Tap (Midwest)
  - Install a 28.8 MVAR capacitor bank at Port Robson (AEPW, Shreveport)
  - Install a 28.8 MVAR capacitor bank at IPC 138 kV (AEPW, Shreveport)

Peak and Off-Peak Changes in SCUC

Hour	SPP units with change in commitment
F1 Peak Hour	10
F1 Off Peak Hour	34
F2 Peak Hour	4
F2 Off Peak Hour	22
F3 Peak Hour	11
F3 Off Peak Hour	12

*Specific units by hour are posted to TrueShare at:

Integrated Transmission Planning – Confidential and Protected Material and or Critical Energy Infrastructure Information-Do Not Release -> 2017 ITP10 -> Output Data -> 20161101_Wind_Profile_Update_8760_Dispatch_Diff.xlsx

Reliability Needs/Projects Summary (Voltage)

- Tap Yoakum - Hobbs 230 kV and Allred - Lea County Waits 115 kV line at intersection, New Sub, New 230/115kV transformer (SPS)
  - This is SP project, and there are no units in the vicinity of south SPS with change of commitment in SP, for F1 or F2
  - F3 SP: Jones 1 gets de-committed, Mustang Station 4 gets committed with the modification. Changed the commitment of these units in the AC model, and there is no discernible change in per unit voltages
- Install 28.8 MVAR cap bank at Atwood and 14.4 MVAR cap bank at Sequin Tap (Midwest)
  - Project is for F1 peak – no west KS units have change in commitment during this hour, so the need/project should not be any different

Reliability Needs/Projects Summary (Voltage)

- Install a 28.8 MVAR capacitor Bank at Port Robson (AEPW, Shreveport)
  - There are units with changes in commitment in this area; however, this voltage issue seems to be driven by the 100 MW load at Port Robson (up from ~40 MW in previous studies) that would probably need a cap bank regardless of the unit commitment in this area
  - F1 SP and F2 SP: No units with changes in commitment in this area.
  - F3 SP: Lieberman 2 gets de-committed, New CT #2 at Knox Lee gets de-committed with this modification. Changed the commitment of these units in the AC model, and there is no discernible change in per unit voltages.
  - 28.8 MVAR is still the right size for this cap bank addition. This need is driven by the 100 MW of load to be served radially at Port Robson, and not driven by generating units.
- Install a 28.8 MVAR capacitor bank at IPC 138 kV (AEPW, Shreveport)
  - Needed only for local planning criteria
  - Project in non-CPP consolidated portfolio, but <u>not</u> CPP consolidated portfolio
  - F3 off peak: Eastex Cogen 2 gets committed with the modification. Changed the commitment of this unit in the AC model, and there is no discernible change in per unit voltages. There is so little generation running in this area that there is no discernible impact.
  - 28.8 MVAR is still the right size for this cap bank

*Remaining work in bold

Conclusion

- Economic needs are very similar between the original case and the modified case
  - Staff expects selected projects would show similar benefit in the modified case
  - **We will test this hypothesis by comparing individual project B/Cs between the original and modified cases for all consolidated portfolio projects**
  - **The Knoll – Post Rock 230 kV second circuit is in the CPP Consolidated Portfolio, but not the Reference Case portfolio. We will test this project in F3, and the results may have an impact on whether or not the project gets an NTC recommendation (slide 6).**
- No reliability projects are impacted by the wind profile modification
  - This is based on looking at differences in unit commitment for reliability hours; there was no new DC/AC conversion
- **We are applying the wind profile modification to the sidebar models. The sidebar models will be used in the Additional Project Analysis, and will be used to test final projects to assess their viability in light of NTC updates and other model corrections**

Anything else??

Identified by TPITF (in Whitepaper)
Identified by SPP Staff

Scope Item	Category
System topology	Model development
Load forecasts - Powerflow	Model development
Load forecasts - Economic	Model development
Economic model development	Model development
DC ties and lines - Powerflow	Model development
DC ties and lines - Economic	Model development
Phase-shifting transformers	Model development
Generation resources - 10 year	Model development
Transmission service	Model development
PSSE Aux File Validation	Model development/Assessments
Fuel prices	Model development
Hurdle rates	Model development
Hourly load shapes	Model development
Renewable modeling	Model development
Economic model generation parameters	Model development
Generation resources - Economic	Model development
Exports/imports - first tier - Powerflow Model	Model development
Exports/imports - first tier - Economic Model	Model development
Benchmarking - Powerflow Model	Model development
Benchmarking - Economic Model	Model development

Renewable survey	Model development/Assessment
Resource plans	Model development
Siting plan	Model development
Generator Outlet Facilities	
Market structure	Model development
ITP/SPP BA model	Model development
Reactive needs for converting Economic Model	Model development
Define constraints (economic model)	Model development/Assessments
Supplemental data for non-compliance to submittal deadlines	Model development
NERC TPL-001-4	Model development/Assessments
Needs assessment - Economic	Assessments
Needs assessment - Reliability	Assessments
Needs assessment - Operational Needs	Assessments
Needs assessment - Reliability/Economic	Assessments
Needs assessment - Policy	Assessments
DPP window	Solutions
Criteria for Project Selection - Economic	Solutions
Criteria for Project Selection - Policy	Solutions
Criteria for Project Selection - Reliability	Solutions
Solution Development - Operational	Solutions
Conceptual cost estimates	Solutions
Upgrade determination and study cost estimates	Solutions
Portfolio development	Solutions
Consolidation	Solutions
Staging	Solutions/Final assessments
40-year financial analysis	Final assessments
Benefit metrics	Final assessments
Sensitivities	Final assessments
Stability assessment	Final assessments

Interregional consideration	Model development/Assessments/Solutions/Final assessments

Stakeholder Group	SME timing	WG timing
TWG	Nov-16	Jan-17
TWG/ESWG	Nov-16	Dec-16
ESWG	Oct-16	Oct-16
ESWG	Oct-16	Feb-17
TWG	Nov-16	Jan-17
ESWG	Oct-16	Jan-16
TWG/ESWG	Dec-16	Feb-17
TWG	Nov-16	Jan-17
TWG	Nov-16	Jan-17
TWG	Nov-16	Jan-17
ESWG	Oct-16	Oct-16
ESWG	Dec-16	Mar-17
ESWG	Oct-16	Oct-16
ESWG	Nov-16	Jan-17
ESWG	Oct-16	Oct-16
ESWG	Dec-16	Feb-17
TWG	Dec-16	Jan-17
ESWG	Jan-17	Mar-17
TWG	Dec-16	Jan-17
ESWG	Jan-17	Feb-17

ESWG	Nov-16	Jan-17
ESWG	Oct-16	Jan-17
ESWG/TWG	Oct-16	Jan-17
TWG	Nov-16	Dec-16
ESWG	N/A	N/A
TWG/ESWG	Dec-16	Mar-16
TWG	Nov-16	Dec-16
TWG	Dec-16	Mar-16
MDWG/ESWG	Sep-17	Apr-17
TWG	Nov-16	Mar-17
ESWG	Dec-16	Mar-17
TWG	Jan-17	Mar-17
ORWG (TWG/ESWG)	Nov-16	Jan-17
ESWG/TWG	Feb-17	Apr-17
ESWG	Jan-17	Mar-17
ESWG/TWG	Jan-17	Mar-17
ESWG	Jan-17	Mar-17
ESWG	Jan-17	Mar-17
TWG	Jan-17	Mar-17
ORWG	Jan-17	Mar-17
ESWG/TWG	Jan-17	Mar-17
ESWG/TWG/CTP TF	Jan-17	Mar-17
ESWG/TWG	Jan-17	Mar-17
ESWG/TWG	Dec-16	Dec-16
ESWG/TWG	Nov-16	Mar-17
ESWG	Jan-17	Mar-17
ESWG	Jan-17	Mar-17
ESWG/TWG	Jan-17	Mar-17
TWG	Jan-17	Mar-17

ESWG/TWG	Nov-16	Mar-17

Notes/Considerations	Status
Criteria for inclusion of future transmission projects in 8760 analysis.	
Load review data: peak load and annual energy by company.	
Review of monthly peak and monthly peak percentages.	Complete Oct.
Catch-all for additional items not listed explicitly:	
Utilization of latest release of ABB Reference Case.	
Emission Prices	
Hydro transaction modeling	Emission prices
External transaction modeling (transfers to non-translated regions)	complete Oct.
Hourly transaction modeling as proxy for DC tie flows.	DC ties Complete
Modeling of DC line limits.	Oct.
Reflecting reasonable operation	
10th year reliability scenario model (non-SPPBA)	
Utilization of latest release of ABB Reference Case	Complete Oct.
What data source and update methodology?	
Data source. Update methodology.	Complete Oct.
Modeling of hourly wind profiles (data source, historical year).	
Methodology for periodic updates.	
VOM/Curtailment pricing.	
Generation review data.	Complete Oct., discuss new functionality for annual energy limits
Discuss expected updates versus modifications to errant data.	
Criteria adjustments for Resource Addition Requests process for new resource inclusion. Depending on level of firmness, can be capacity and technology requests only, following standardized resource siting methodology.	
Determine the model(s) and data items. Consider frequency needed.	

Determine survey structure. Future usage.

Resource capacity expansion and technology methodology.
Prototypes.
Accreditation (renewable, existing and future) SPP renewable
Capacity Factor assumptions (future renewable, prior to resource siting) complete Oct.

Definition of CBA for SPP.
ESWG action item related to DC/AC conversion

Process for defining constraints considering 2, 5, and 10-year models, new TPL planning events, new and updated interface limits.

Methodology for defining reliability needs for non-reliability hours.

Interaction between planning and operations.
Interaction between model years.
Interaction between reliability and economics.
Utilization of metrics beyond APC.
Utilization of policy survey. Future policy changes.

10/6/16

Objective:

The TPITF made several recommendations to the current planning process to improve the identification of projects and process timelines. Per the TPITF white paper recommendation SPP staff has developed strawman criteria in order to identify chronic operational events that need long term transmission solutions proposed. This criteria will be inserted into the ITP Manual.

- Flowgate issues
  - Flowgates must reference monitored elements under the SPP Tariff. Flowgates congested for at least 20% of the previous 24 months, either in a breached or binding state in the Real-Time Balancing Market solution, will be added to the ITP needs list. Periods of time when a flowgate's related congestion is deemed to be the result of an outage(s) will be excluded.
  - Flowgates with congestion costs totaling more than $10 million over the previous twenty four months will also be added to the ITP needs list. Congestion costs will be calculated using the same methodology as the VRL Report process. Periods of time when a flowgate's related congestion is deemed to be the result of an outage(s) will be excluded.
  - IROL Flowgates identified in operations shall be added to the needs list.
- High/Low Voltage issues
  - Operating Guides that require reconfiguration, documenting mitigations for high and low voltage issues, will be reviewed from the last cycle and related voltage issues will be added to the ITP needs list. The mitigation to avoid the high/low voltage issue must be implemented 10% of the time of the year due to non-outage issues.
    - Mitigations that are implemented less than 10% of the year, but risk greater than 100 MW of load will also be considered.
- Manual Commitments (Economic)
  - Generation that is dispatched uneconomically in order to support voltage in the local area. Manual commitment events which include startup and extension 25% of the year will be added to the ITP needs list. DPP solutions will be compared against the Make Whole Payments during the cycle as well as expected payments over the next 40 years. Make Whole Payments occurring over the last cycle will be compared to transmission solutions to see if a B/C ratio is greater than .9.

- N-1-1 (outage scenarios)
    - Operations will identify situations during outages that may result in the loss of load in the event of the next contingency due to a lack of voltage support or lack of transmission sources to serve load. In circumstances that risk the loss of load transmission solutions would be required. Load risk issues must be present at least 10% of the year. If there are long term solutions planned for the area then the need for additional support would be excluded.
        - 100 MW of load at risk would be an alternative to not showing up 10% of the time
- Required reconfigurations due to ineffective redispatch
    - Transmission capacity limitations can usually be controlled by flowgates. Applying a threshold to TDFs can leave some transmission paths overloaded with no way to control loading through redispatch. Reconfiguration will relieve the most limiting element, but it often degrades the robustness of the transmission system and increases risk due to the next contingency. The reconfiguration will require an agreed upon Operating Guide that has been implemented in real time 25% of the year.

Project Acceleration:

- Projects that have previously been identified by SPP Planning may be subject to Accelerated Need Dates based on issues identified in Real Time Operations.

Objective:

The TPITF made several recommendations to the current planning process to improve the identification of projects and process timelines. Per the TPITF white paper recommendation SPP staff has developed strawman criteria in order to identify chronic operational events that need long term transmission solutions proposed. An initial list of chronic operational issues has been identified below based on the proposed criteria.

Flowgate Issues:

- Congested > 20% of previous 24 months
  - OSGCANBUSDEA
    - 50,670 market intervals or 24.1%

- VRL Analysis, > $10 million over previous 24 months

Cost of Congestion	IDC Number	Flowgate Name	Element Type	Area	Element
$77,081,843	5563	WDWFPLTATNOW	Monitored	OKGE	Woodward - FPL Switch 138 kV
	5563	WDWFPLTATNOW	Contingent	OKGE	Tatanga - Matthewson 345 kV
$42,192,030	5371	OSGCANBUSDEA	Monitored	SPS	Osage - Canyon East 115 kV
	5371	OSGCANBUSDEA	Contingent	SPS	Bushland - Deaf Smith 230 kV
$21,010,899	5548	SUNAMOTOLYOA	Monitored	SPS	Sundown - Amoco 230 kV
	5548	SUNAMOTOLYOA	Contingent	SPS	Tolk - Yoakum 230 kV
$18,256,273	5228	IATSTRNASHAW	Monitored	KCPL	Iatan - Stranger 345 kV
	5228	IATSTRNASHAW	Contingent	KCPL	Nashua - Hawthorn 345 kV
$13,674,547	21931	TMP203_21931	Monitored	OKGE	CIMARRON 345/138 kV Transformer CKT 1
	21931	TMP203_21931	Contingent	OKGE	CIMARRON 345/138 kV Transformer CKT 1
$13,072,821	5577	NASXFRNASHAW	Monitored	KCPL	Nashua 345/161 kV Transformer
	5577	NASXFRNASHAW	Contingent	KCPL	Nashua - Hawthorn 345 kV
$12,033,385	5567	WODFPLWODXFR	Monitored	OKGE	Woodward - FPL Switch 138 kV
	5567	WODFPLWODXFR	Contingent	OKGE	Woodward 138/69 kV Transformer
$10,359,270	5576	SILSPRTONFLI	Monitored	GRDA	Siloam - Siloam Springs 161 kV
	5576	SILSPRTONFLI	Contingent	GRDA	Tonnece - Flint Creek 345 kV

- IROLs:

IDC Number	Flowgate Name	Flowgate Type	Area	Element
5042	NWTPATLYDVAL	Monitored	CSWS	NW Texarkana - Patterson 138 kV
5042	NWTPATLYDVAL	Contingent	CSWS	Valliant - Lydia 345 kV
5215	VALLYDELDSAR	Monitored	CSWS	Valliant - Lydia 345 kV
5215	VALLYDELDSAR	Contingent	EES	ElDorado - Sarepta 345 kV
5217	SARELHVALLYD	Monitored	EES	Sarepta - Longwood 345 kV
5217	SARELHVALLYD	Contingent	CSWS	Valliant - Lydia 345 kV
6006	GGS	Monitored	NPPD	Gentleman - North Platt 230 kV CKT 1
6006	GGS	Monitored	NPPD	Gentleman - North Platt 230 kV CKT 2
6006	GGS	Monitored	NPPD	Gentleman - North Platt 230 kV CKT 3
6006	GGS	Monitored	NPPD	Gentleman - Red Willow 345 kV
6006	GGS	Monitored	NPPD	Gentleman - Sweewater 345 kV CKT 1
6006	GGS	Monitored	NPPD	Gentleman - Sweewater 345 kV CKT 2

High/Low Voltage Issues:

- Brookline – Flint Creek 345 kV
    - 82 days or 22.47% of previous 12 months

Required Reconfiguration due to Ineffective redispatch:

- Red Willow 345/115 kV transformer
    - 135.8 days or 37% of previous 12 months

ITP Scope Standardization – Resource Planning

ESWG

11/16/2016

Conventional Additions – SPP

- Assess resource shortfall by pricing zone, based on reserve margin
  - Account for existing load, existing generation, and new wind and solar additions
- Identify conventional generation prototype parameters – recommend use of the latest Lazard Levelized Cost of Energy Analysis
- Resource expansion tool(s) will be utilized to identify the optimum mix of new conventional resources to add in order to meet reserve margin requirements by zone
  - No siting involved in this process

External RP Proposal – Conventional

- MISO – use conventional resource additions from the most current MTEP model (future-specific)
- AECI, TVA, SaskPower, Manitoba, any others – calculate resource additions by spreadsheet
  - Start with capacity shortfall calculations
  - Add conventional units with a resource mix that is as close as possible to the SPP resource addition mix for that future
    - For example, if SPP additions include 60% CCs and 40% CTs, use a similar 60/40 ratio for additions in these external regions, as much as is possible with standard prototype units
    - However, if the existing resources in an external region have a different ratio of peaking to total gen than SPP's peaking to total gen ratio, the new resource ratio (60% CC/40% CT, for example) shall be adjusted accordingly

SPP Wind Export Additions

- Calculate ratio of (existing export wind)/(total existing wind)
  - Then add export wind in order to keep the same ratio for (export wind additions)/(total wind additions)
- Example: 10 GW existing wind for SPP entities, 1 GW existing wind for export
  - If adding 4 GW of wind for SPP entities, add 400 MW of wind for export

RP Proposal – Baseline

- Members submit expected future generation (conventional/renewable) through the MDWG model development process
  - Load and generation review
  - Reflective of company IRP
  - No siting considerations at this stage
- Use member-submitted generation parameters
  - If member is unable to provide parameters, ABB Reference Case data for that technology type would be used

Resource Plan – Years 2, 5, 10

- Year 2
  - High Certainty for any planned resource additions
  - Ensure region meets reserve margin requirements
    - SPP will not identify resource additions
    - IPP resources assigned to resource deficient zones
- Years 5 and 10
  - Could have Less Certainty for forecasted resource additions
  - Wind and solar unit additions based on uniform criteria (approved October)
  - Add conventional resource plan units as needed to meet reserve margin requirements in these years


SPP
75th Anniversary
75
SEVENTY-FIVE YEARS OF
RELIABILITY THROUGH RELATIONSHIPS

ITP Resource Siting Plan

November 16th, 2016

ESWG

Chris Jamieson

Resource Siting Plan - Conventional

- Investigating process questions and details for members to add publicly available Integrated Resource Planning resources with siting into Model on Demand
  - Consideration of applicability to different SPP study processes
  - Requirement for Resource Addition Requests
- Leverage conventional generation siting repository
  - Collection of sites from GI Queue, previous studies, staff and member alternatives
  - Includes retirement dates of existing resources for replacement
  - Includes transmission interconnection capability screening
  - Provided to members for new site updates and ranking at beginning of milestone
  - Rank sites by zone
  - Tracking of study to study resource plans
- Assignment by Zone

Resource Siting Plan - Wind

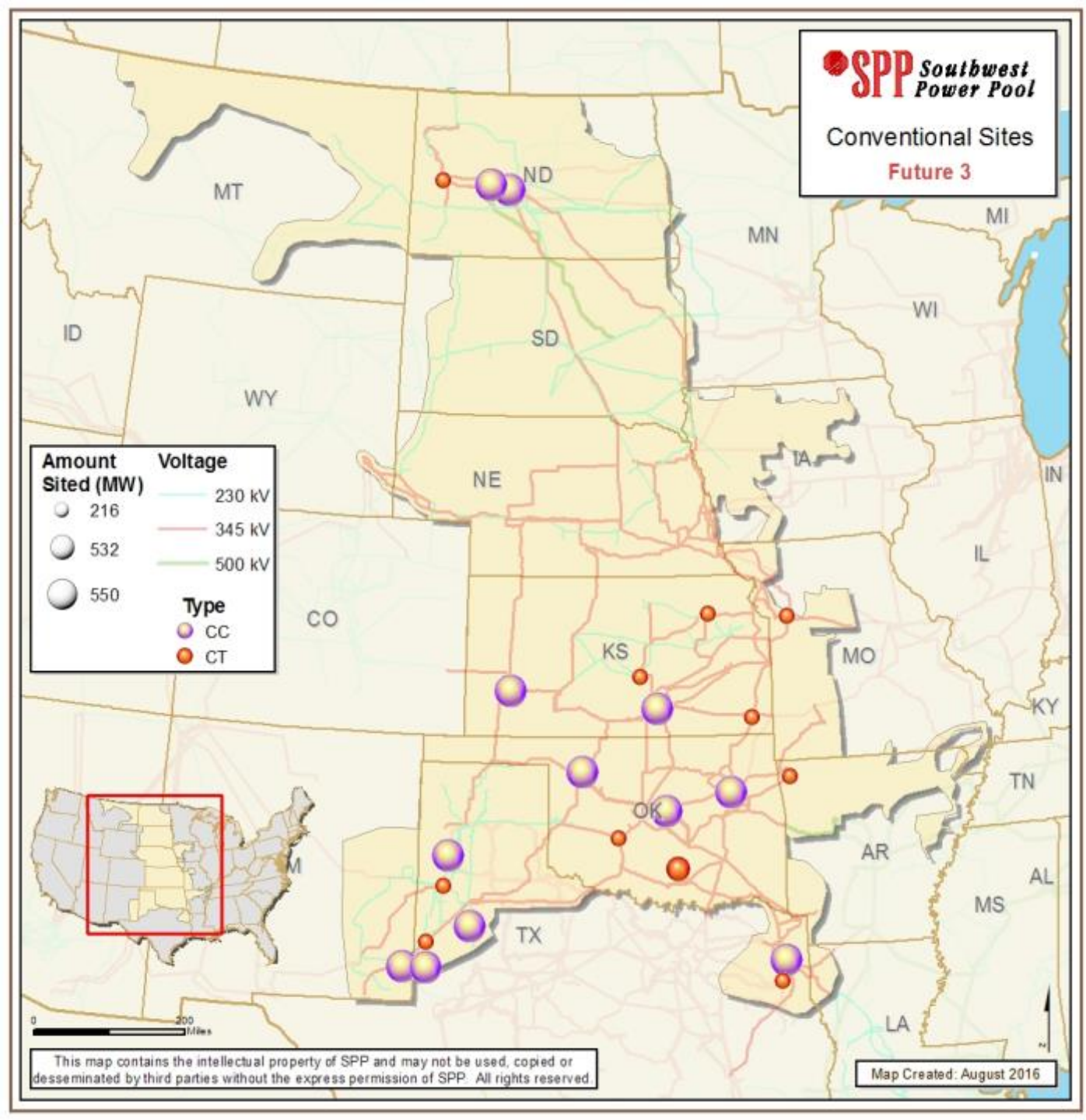
- Leverage Generation Interconnection queue until such time the resources plan additions exceed ranked statuses
- Ranked generation interconnection queue statuses
  - IA on-schedule
  - IA on-suspension
  - IA commercial operation not fully on-line
  - IA Pending
  - Facility Study
- Additional rankings by capacity factor by interconnection costs
- Assignment by Zone by State by Region

Resource Siting Plan - Solar

- Leverage Generation Interconnection queue then supplement using NREL comprehensive data set
- Additional rankings by capacity factor by interconnection costs or interconnection capability screening
- Assignment by Zone by State by Region

2017 ITP10 Siting Plan

Conventional Maps


SPP Southwest Power Pool
Conventional Sites
Future 3
Amount Sited (MW)
216
532
550
Voltage
230 kV
345 kV
500 kV
Type
CC
CT
MT
ND
MN
MI
ID
SD
WI
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
AL
MS
TX
LA
0
200
Miles
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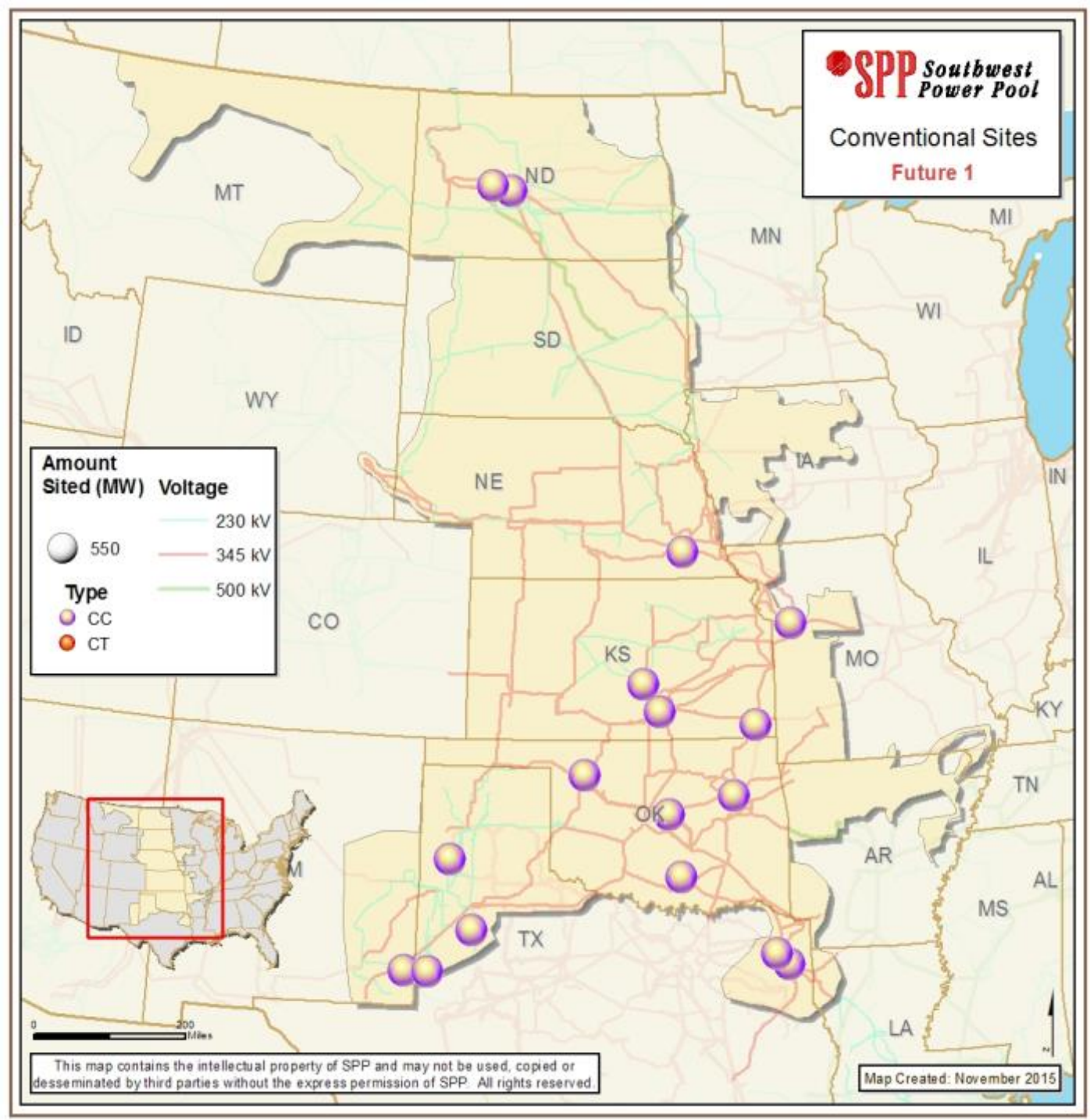
Map Created: August 2016


SPP Southwest Power Pool
Conventional Sites
Future 1
Amount Sited (MW)
550
Type
CC
CT
Voltage
230 kV
345 kV
500 kV
ND
MT
MN
MI
WI
ID
SD
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
AL
MS
TX
LA
0
200
Miles
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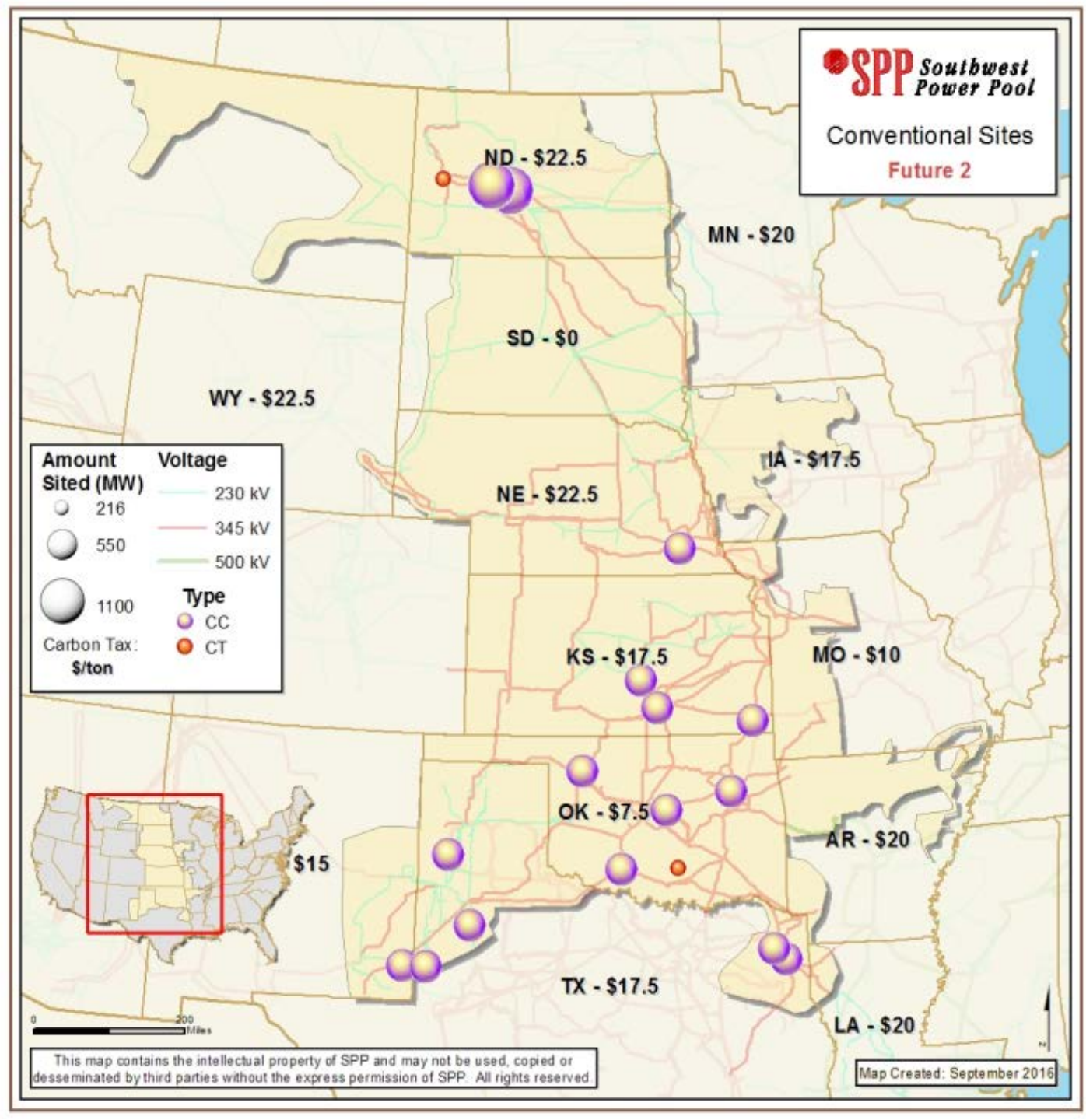
Map Created: November 2015


SPP Southwest Power Pool
Conventional Sites
Future 2
ND - $22.5
MN - $20
SD - $0
WY - $22.5
IA - $17.5
NE - $22.5
KS - $17.5
MO - $10
OK - $7.5
AR - $20
$15
TX - $17.5
LA - $20
Amount Sited (MW)
216
550
1100
Carbon Tax: $/ton
Voltage
230 kV
345 kV
500 kV
Type
CC
CT
0
200
Miles
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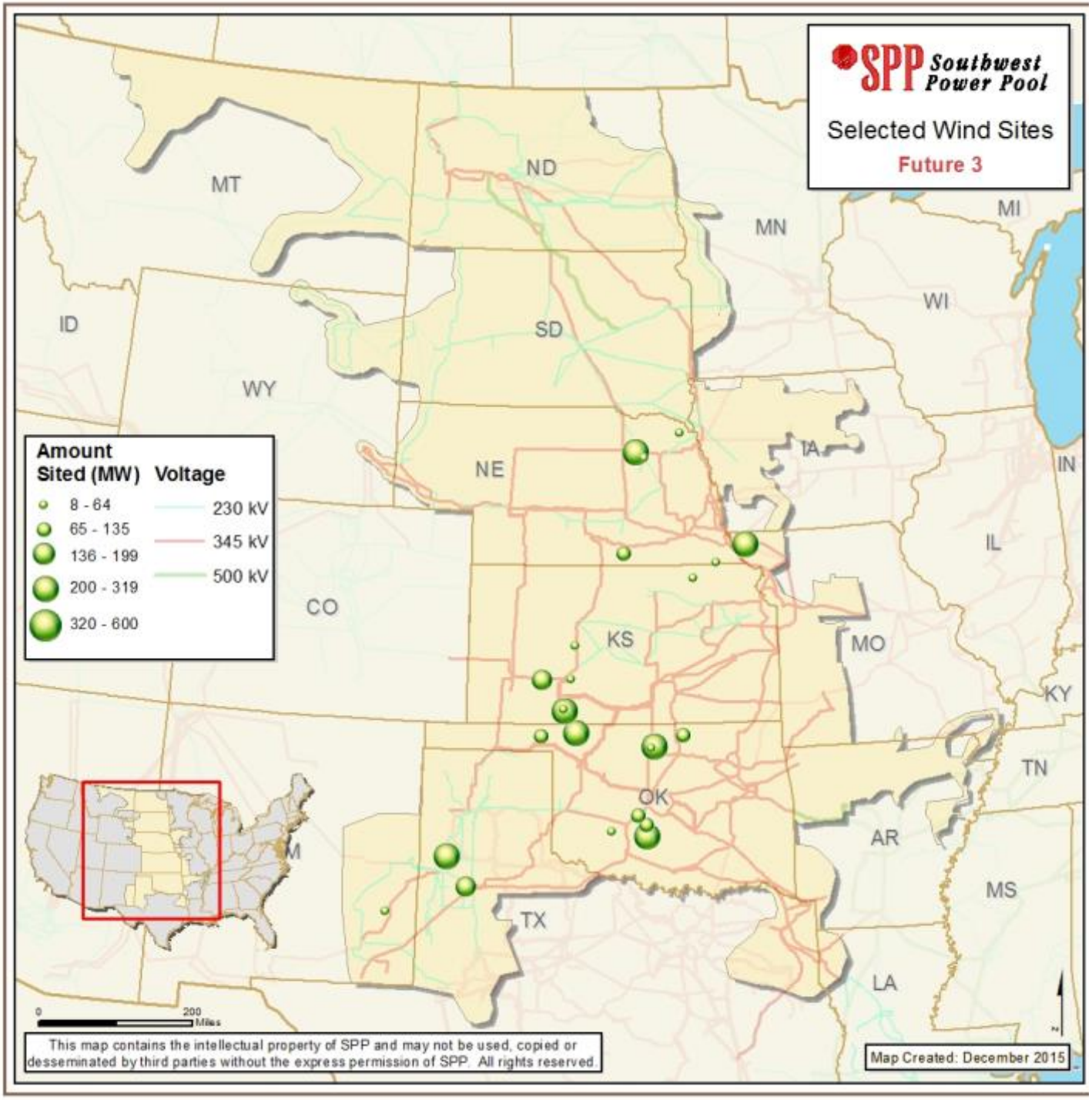
Map Created: September 2016

C

2017 ITP10 Siting Plan

Wind Maps


SPP Southwest Power Pool
Selected Wind Sites
Future 3
Amount Sited (MW)
8 - 64
65 - 135
136 - 199
200 - 319
320 - 600
Voltage
230 kV
345 kV
500 kV
MT
ND
MN
MI
ID
SD
WI
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
MS
TX
LA
0
200
Miles
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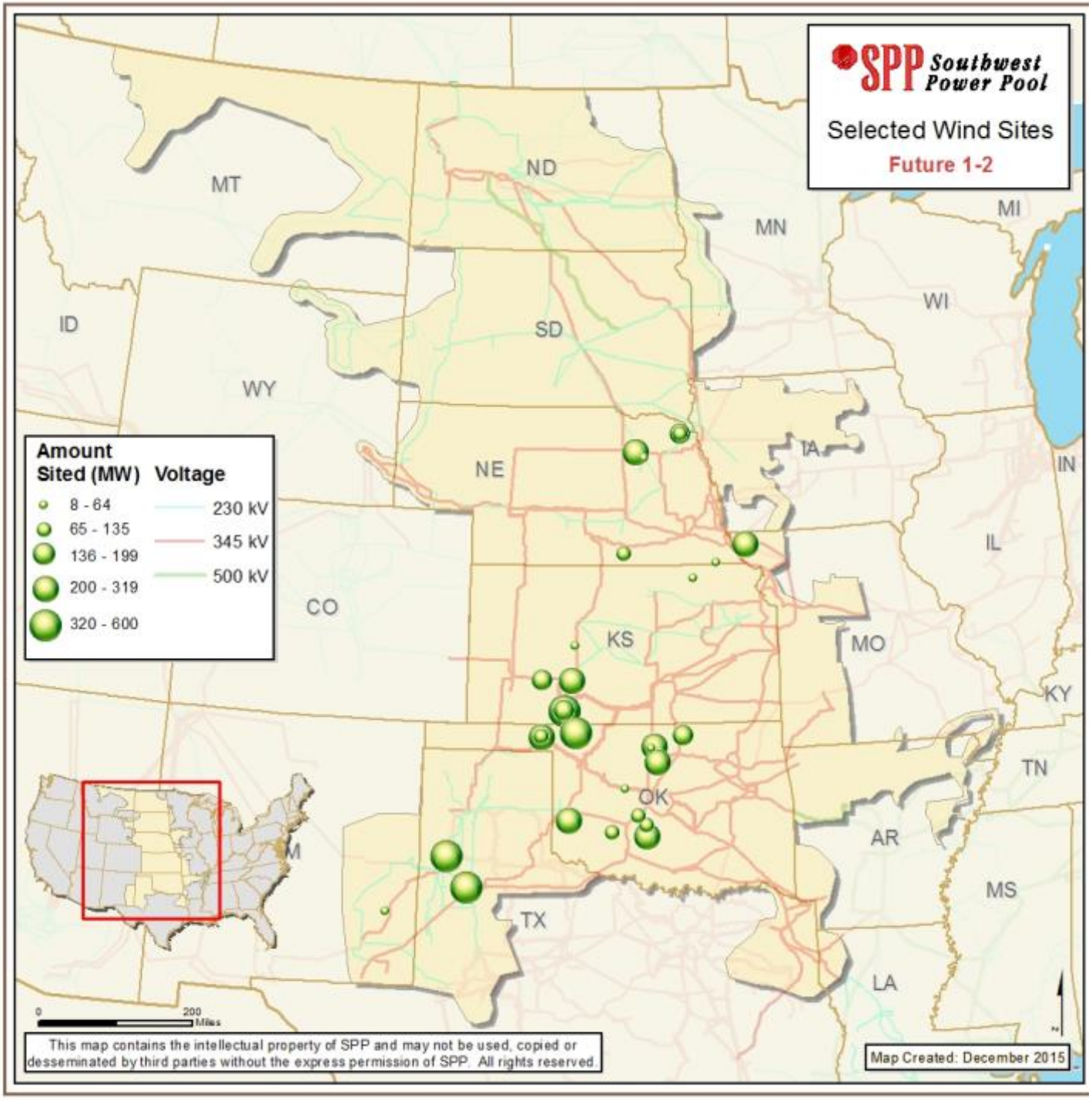
Map Created: December 2015


SPP Southwest Power Pool
Selected Wind Sites
Future 1-2
Amount Sited (MW)
8 - 64
65 - 135
136 - 199
200 - 319
320 - 600
Voltage
230 kV
345 kV
500 kV
MT
ND
MN
MI
ID
SD
WI
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
MS
TX
LA
0
200
Miles
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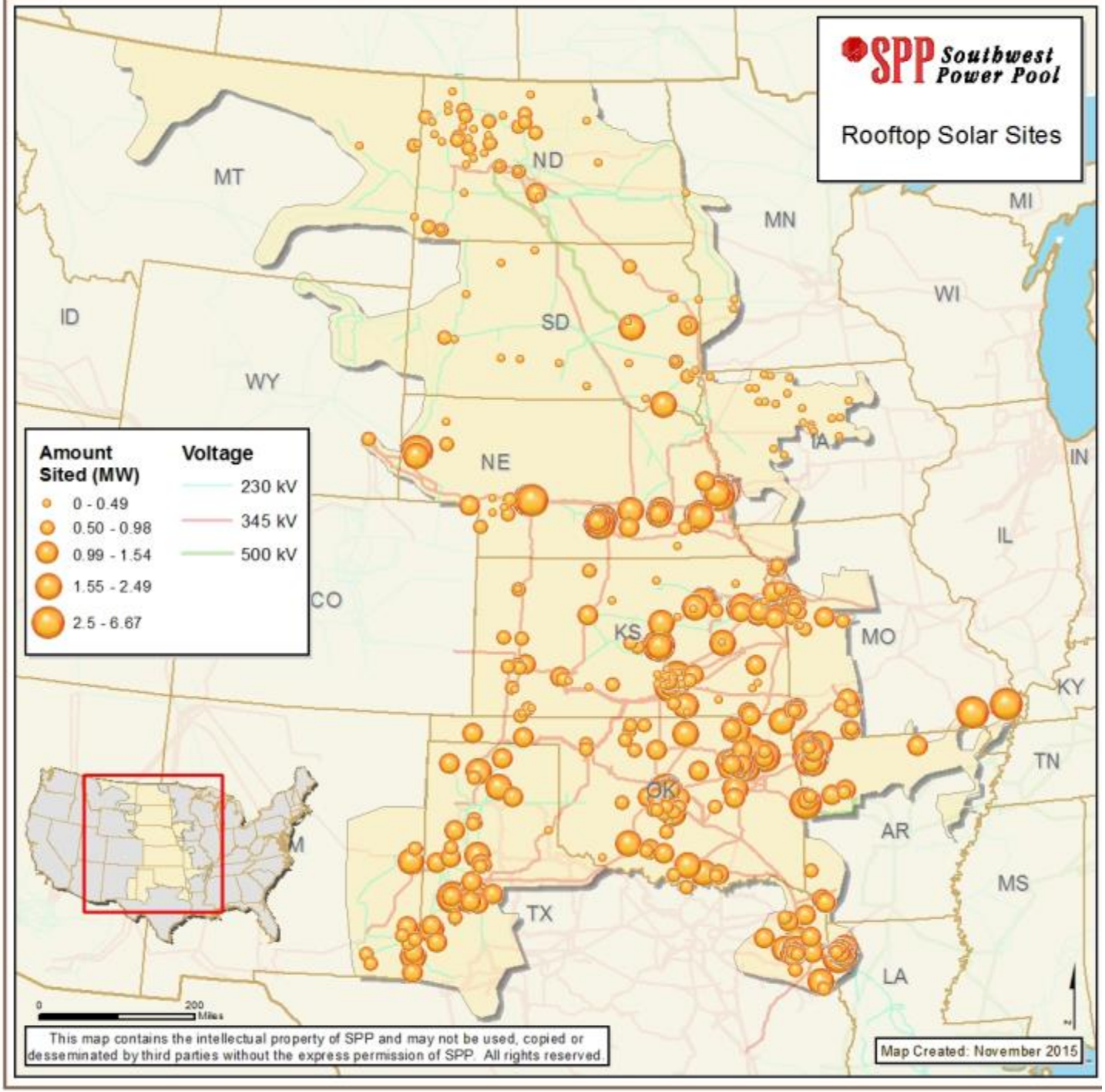
2017 ITP10 Siting Plan

Solar Maps


SPP Southwest Power Pool
Rooftop Solar Sites
Amount Sited (MW)
0 - 0.49
0.50 - 0.98
0.99 - 1.54
1.55 - 2.49
2.5 - 6.67
Voltage
230 kV
345 kV
500 kV
MT
ND
MN
MI
WI
ID
SD
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
MS
TX
LA
0
200
Miles
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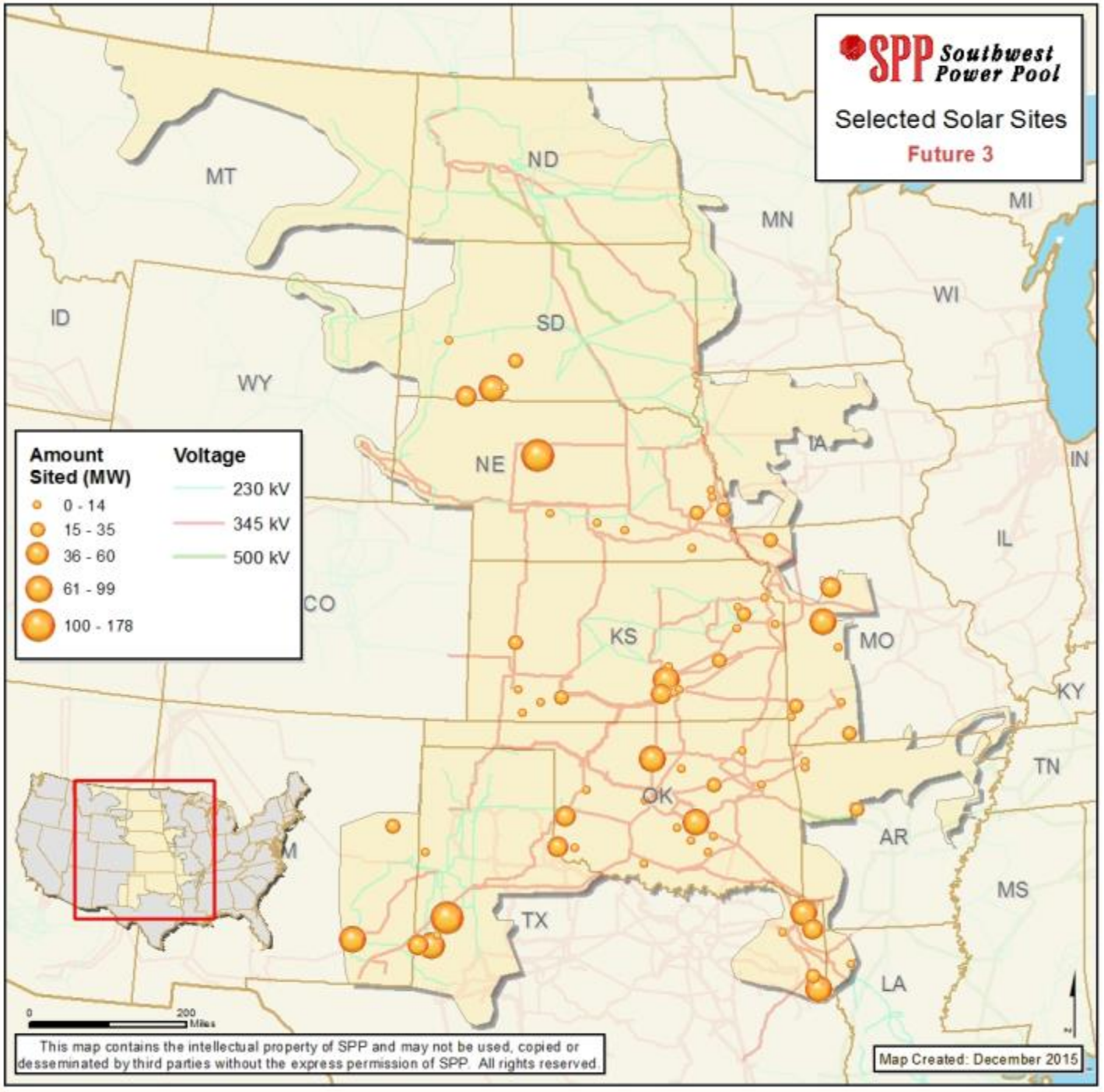
SPP Southwest Power Pool
Selected Solar Sites
Future 3
Amount Sited (MW)
0 - 14
15 - 35
36 - 60
61 - 99
100 - 178
Voltage
230 kV
345 kV
500 kV
MT
ND
MN
MI
ID
SD
WI
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
MS
TX
LA
0
200
Miles
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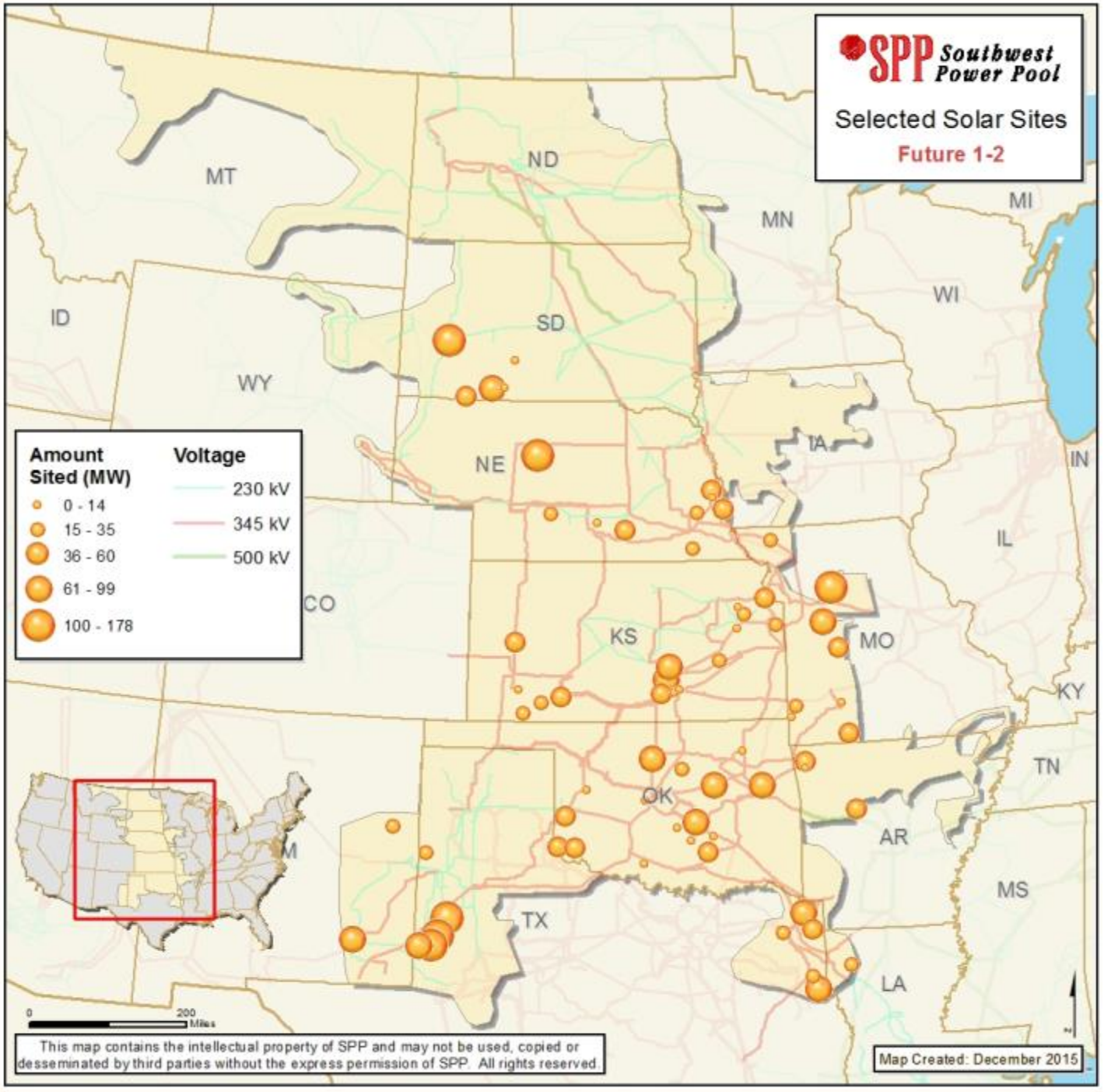
SPP Southwest Power Pool
Selected Solar Sites
Future 1-2
Amount Sited (MW)
0 - 14
15 - 35
36 - 60
61 - 99
100 - 178
Voltage
230 kV
345 kV
500 kV
MT
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SD
WI
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IN
IL
CO
KS
MO
KY
TN
OK
AR
MS
TX
LA
0
200
Miles
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ITP Scope Standardization – Policy Survey

Liz Gephardt

2017 ITP10 Policy Survey

- Process
  - Survey to members for Regulatory/Statutory Mandates and Goals in staging and study years
  - Feeds into Resource Plan and Policy Needs Assessment
- 7 week time frame
  - 3 weeks SPP staff prep and processing results
  - 4 weeks of member review/feedback
- Resource Time
  - 48.5 SPP staff hours
  - Unknown utility contact hours
- Results
  - <400 MW of renewables
  - No Policy Needs

ITP Standard Policy Survey Recommendation

- SPP staff recommends standardizing percentages of load and/or generation for each utility by state to calculate Mandates and Goals. These percentages would be based on historical values used and member feedback, and would be used as a standard proxy for future renewable energy standards.

Proposed Standard Values

- States not included in the table would have no standard percentage

State	RPS Type	Capacity- or Energy-Based	Gen- or Load-Oriented	Year 2 %	Year 5 %	Year 10 %
Kansas	Goal	Capacity	Load	20	20	20
Minnesota	Mandate	Energy	Load	20	20	25
Missouri	Mandate	Energy	Load	15	15	15
Montana	Mandate	Energy	Load	15	15	15
North Dakota	Goal	Energy	Load	10	10	10
New Mexico	Mandate	Energy	Load	20	20	20
Oklahoma	Goal	Capacity	Gen	15	15	15
South Dakota	Goal	Energy	Load	10	10	10
Texas	Mandate	Capacity	Load	5	5	5

ITP Scope Standardization – Wind Modeling

ESWG

11/16/16

Wind Modeling – Economic Parameters

- PROMOD has two primary economic modeling parameters impacting wind dispatch, curtailment, and production cost
  - Curtailment price
  - Variable O&M
- SPP currently uses $8/MWh for both of these, for all wind units

Wind Curtailment Price

- Defines the trigger price at which wind will curtail
- If curtailment price is $8/MWh, wind will curtail if the LMP at the unit drops to $7/MWh
  - If the LMP stays above $8/MWh, the wind dispatch will follow the defined hourly profile for that unit
  - The curtailment price impacts dispatch/curtailment, but does not impact unit production costs
- Staff analyzed historical offer prices in the Integrated Marketplace, 2014 – 2016
  - After removing extreme outliers, -$23/MWh was the average offer price
  - There is some variability; some prices are higher, even above zero, while many offers are around -$60/MWh, due to the PTC + PPA price
- Option 1: Use -$23/MWh for curtailment price, which would account for a PTC
- Option 2: Use $0/MWh for curtailment price, which does not account for a PTC
  - ABB recommendation
  - Staff recommendation

Wind Variable O&M

- Defines the operating cost per MWh
- Does not impact dispatch/curtailment, but directly impacts production cost and APC benefit
- Three ideas for defining this
  - Use approximate operating cost (~$0/MWh)
  - Use approximate PPA price
  - Use some kind of a compromise between the operating cost and PPA price (such as $8/MWh, or higher)
- Staff recommends using $8/MWh as variable O&M for wind

Appendix

PTC ($/MWh)

All values shown in Present Value ($/MWh)		PTC	Wind Farm Construction														
	Year		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Jan. 1, 2020
	2006	100%	$ 23														
	2007	100%	$ 23	$ 23													
	2008	100%	$ 23	$ 23	$ 23												
	2009	100%	$ 23	$ 23	$ 23	$ 23											
	2010	100%	$ 23	$ 23	$ 23	$ 23	$ 23										
	2011	100%	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23									
	2012	100%	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23								
	2013	100%	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23							
	2014	100%	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23						
	2015	100%	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23					
Steps Down	2016	100%		$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23				
	2017	80%			$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 18			
	2018	60%				$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 18	$ 14		
	2019	40%					$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 18	$ 14	$ 9	
	2020	0%						$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 18	$ 14	$ 9	0
	2021	0%							$ 23	$ 23	$ 23	$ 23	$ 23	$ 18	$ 14	$ 9	0
	2022	0%								$ 23	$ 23	$ 23	$ 23	$ 18	$ 14	$ 9	0
	2023	0%									$ 23	$ 23	$ 23	$ 18	$ 14	$ 9	0
	2024	0%										$ 23	$ 23	$ 18	$ 14	$ 9	0
	2025	0%											$ 23	$ 18	$ 14	$ 9	0
	2026	0%												$ 18	$ 14	$ 9	0
	2027	0%													$ 14	$ 9	0
	2028	0%														$ 9	0
END	2029	0%															0

NOTE: After construction begins the tax payer has 4 years to complete construction, e.g. a wind facility starting construction in 2019 could begin operation in 2023, and the PTC would expire in 2033.
https://www.irs.gov/irb/2016-23_IRB/ar07.html

Meeting Locations

February 22-23 – Austin, TX

May 17-18 – St. Louis, MO

August 16-17 – Denver, CO

November 15-16 – Little Rock, AR

Southwest Power Pool
Economic Studies Working Group
Charter
October 27th, 2015

PURPOSE

The Economic Studies Working Group (ESWG) advises and assists Southwest Power Pool (SPP) Staff in the determination of the appropriate data, planning methods and processes to be used in the development and evaluation of economic transmission expansion options for the SPP region. The ESWG will be responsible for data, sources, models, economic planning methodology, timing and implementation, application, economic parameters and metrics to be used in the development and evaluation of economic expansion options in the SPP region. The ESWG will also review the economic planning processes used by SPP Staff and offer proposals for improvement of these processes. The ESWG will be responsible for all economic modeling parameters and data for the SPP region, and will conduct as needed updates to all data for the stakeholders on a regular basis as appropriate for regional planning needs. Additionally, the ESWG will be responsible for ensuring that third party consultants contracted by the SPP have access to the most appropriate, updated data.

SCOPE OF ACTIVITIES

In carrying out its purposes, the ESWG will:

1. Provide oversight, data inputs and review, as appropriate, of economic planning studies performed by the SPP, including but not limited to:
   - Integrated Transmission Planning (ITP) – provide input into the economic portions of the ITP process
   - Balanced Portfolio – Provide guidance to the CAWG on input assumptions and modeling techniques used in the Balanced Portfolio analysis
   - High Priority – support other high priority economic studies, as applicable
   - Coordinated System Planning – provide input into economic studies performed in coordination with neighboring regions or entities
   - Regional Cost Allocation Review (RCAR) – provide input into the RCAR analysis and provide guidance to the Regional Allocation Review Task Force (RARTF), as needed

2. Provide oversight of the economic study process performed by the SPP, including but not limited to, economic transmission plan development, project interaction and the overall economic planning process

3. Provide oversight of and review Loss of Load Expectation (LOLE) studies performed by the SPP

4. Provide input to the SPP in evaluation of the impact of market mechanisms on planning studies

5. Establish study standard assumptions for economic analysis; determine, update and vet the necessary data and inputs required to model, study, and evaluate economic alternatives

6. Define and update any terms used in the economic transmission planning process, including data, metrics and assumptions that provide clear understanding to conduct economic studies for SPP

7. Identify, review and modify the metrics for overall quantification and break-out of economic impacts beyond adjusted production cost savings

8. Review the solution techniques and provide recommendations for improvements and/or alternatives

9. Update and maintain the economic planning process documentation to provide controls for economic planning in SPP

10. Provide updates to the MOPC on the status and progress of economic studies and planning in the SPP

REPRESENTATION
ESWG membership will consist of up to the following:
17 Voting members –

- 5 Transmission Owning
- 5 Transmission Using
- 5 Generation
- 2 Other

And 1 non-voting Regulatory Liaison member.

DURATION
Permanent.

REPORTING
The ESWG reports to the Market and Operations Policy Committee.

Other Notes:
In light of FERC Orders 888 and 889 and the group composure of transmission and generation parties, the ESWG will have to observe the Standards of Conduct outlined in FERC Order 889. As such, there may be topics discussed by the ESWG that are privileged and confidential. Under such an event, appropriate measures will be taken to ensure that no Standards of Conduct are violated, including but not limited to, closed meetings, closed sessions, etc. Members and participants will be required to adhere to SPP's Nondisclosure Agreement.