Southwest Power Pool

JOINT TRANSMISSION & ECONOMIC STUDIES WORKING GROUP MEETING

May 17, 2017

Hilton at the Ballpark – St. Louis, MO

• Summary of Action Items •

1. Approved the Consent Agenda
2. Approved the Constraint Assessment methodology for the new ITP process

Southwest Power Pool

Southwest Power Pool, Inc.

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May 17, 2017

Hilton at the Ballpark – St. Louis, MO

• M I N U T E S •

Agenda Item 1 – Administrative Items

TWG Chair Travis Hyde and ESWG Chair Alan Myers called the meeting to order at 10:40 am. The following members were in attendance (Attachment 1a, 1b – In-Person Attendance, WebEx Attendance) or represented by proxy:

TWG
Travis Hyde (Chair), Oklahoma Gas & Electric
Daniel Benedict, City of Independence
Jerry Bradshaw, City Utilities of Springfield
Richard Dahl, Missouri River Energy Services
Joe Fultz, Grand River Dam Authority
John Fulton, Southwestern Public Service Company
Kalun Kelley, Western Farmers Electric Cooperative
John Knofczynski, East River Electric Power Cooperative
Randy Lindstrom, Nebraska Public Power District
Jim McAvoy, Oklahoma Municipal Power Authority
Matt McGee, American Electric Power
Nate Morris, Empire District Electric
Michael Mueller, Arkansas Electric Cooperative Corporation
Alan Myers, ITC Great Plains
Gayle Nansel, Western Area Power Administration
Chris Pink, Tri-State G&T
Jason Shook, GDS Associates representing ETEC
Dave Spargo, Omaha Public Power District
Matthew Stoltz, Basin Electric Power Cooperative
Kurt Stradley, Lincoln Electric System
Noman Williams, South Central MCN
Harold Wyble, Kansas City Power & Light

ESWG
Alan Myers (Chair), ITC Great Plains
Randy Collier, City Utilities of Springfield
Jody Holland, South Central MC
Leon Howell, Oklahoma Gas & Electric
Jon Iverson, Omaha Public Power District
Jim Jacoby, American Electric Power
Evan Racine-Johnson, Golden Spread Electric Cooperative
Bethany King, Empire District Electric
Pat McCool, Kansas City Power & Light
Gayle Nansel, Western Area Power Authority
Tim Owens, Nebraska Public Power District
Matthew Stoltz, Basin Electric Power Cooperative
Kurt Stradley, Lincoln Electric System
Michael Watt, Oklahoma Municipal Power Authority

Bennie Weeks, Southwestern Public Service Company

Kirk and Kelsey informed the Chairs of a quorum for their respective groups.

Receipt of Proxies
The following proxies were announced (Attachment 1c – Proxies):

TWG
- Dave Spargo (OPPD) proxy for Dan Lenihan (OPPD)
- Kurt Stradley (LES) proxy for Scott Benson (LES)
- Jerry Bradshaw (CUS) proxy for John Boshears (CUS)

ESWG
- Jim Jacoby (AEP) proxy for Anita Sharma (AEP)
- Matthew Stoltz (BEPC) proxy for Jeremy Severson (BEPC)
- Evan Racine-Johnson (GSEC) proxy for Natasha Henderson

Agenda Item 2 – Consent Agenda

Travis and Alan asked if any TWG or ESWG members preferred discussion on the Consent Agenda (Attachment 2a, 2b – ITP Manual Posting Summary, ITP Manual Draft). No members requested additional discussion.

Motion: John Knofczynski made a motion to approve the consent agenda. Daniel Benedict seconded the motion. The motion was approved unanimously.

Motion: Alan Myers asked the ESWG to cast their vote on the consent agenda. The motion passed unanimously.

Agenda Item 3 – ITP Scope Standardization

Constraint Assessment
Chris Jamieson, SPP staff, presented staff's updated proposal (Attachment 3a – Constraint Assessment) for the constraint assessment for the new ITP process. Neither group had concerns with staff's proposal.

Motion (TWG): Harold Wyble made a motion to accept the methodology for the constraint assessment in the new ITP process. Alan Myers seconded the motion. The motion passed with no opposition.

Motion (ESWG): Kurt Stradley made a motion to accept the methodology for the constraint assessment in the new ITP process. Tim Owens seconded the motion which passed with no opposition.

Agenda Item 4 – Resource Siting Whitepaper Discussion

Chris moved onto Siting (Attachment 3b, 3c – Resource Siting Whitepaper Discussion Presentation, Draft Siting Whitepaper). He presented to the stakeholders the concepts in the draft whitepaper and provided the staff whitepaper for members to provide feedback. He informed the members that Section 4 of the whitepaper would be moved into the ITP Manual.

Respectfully Submitted,

Kirk Hall
TWG Secretary

Kelsey Allen
ESWG Secretary

ECONOMIC STUDIES WORKING GROUP/TRANSMISSION WORKING GROUP

May 17th, 2017

Hilton at the Ballpark – St. Louis, MO

• AGENDA •

10:30am – 12:00pm

1. Administrative Items
   a. Call to Order .... Alan Myers/Travis Hyde (5 minutes)
   b. Receipt of Proxies .... Kelsey Allen/Kirk Hall (1 minute)
2. Consent Agenda[1] (Approval Item).. Alan Myers/Travis Hyde (1 minute)
   a. ITP Manual
3. ITP Scope Standardization .... SPP Staff (80 minutes)
   a. Constraint Assessment (Approval Item) (Chris Jamieson)
   b. Resource Siting Whitepaper Discussion (Chris Jamieson)

[1] Background Material Included

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ECONOMIC STUDIES/TRANSMISSION WORKING GROUP MEETING

May 17, 2017

Hilton at the Ballpark – St Louis, MO

• ATTENDANCE LIST •

Name	Company
David Oswald	EMDE
Bryan Rushing	Quanta Technology
Eric Burkey	SCMCN
Holli Krizek (guest)	WAPA
Steve Gaw	Wind Coalition
James Vermillion	AECI
BRIAN JOHNSON	AEP
JIM JACOBY	AEP
VINOD OLAPURAYIL	ITC Great Plains

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ECONOMIC STUDIES/TRANSMISSION WORKING GROUP MEETING

May 17, 2017

Hilton at the Ballpark – St Louis, MO

• ATTENDANCE LIST •

Name	Company
Jim McAvoy	OMPA
Jody Holland	SCMCN
Norman Williams	SCMCN
Ryan Yokley	Sunflower
Juliano Freitas	SPP
Gayle R Nansel	WAPA
John Knofczynski	EREPC
Daniel Benedict	IPL
Kalun Kelley	WFEC
Matt McGee	AEP
Nate Morris	Empire District
Alan Myers	ITC

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ECONOMIC STUDIES/TRANSMISSION WORKING GROUP MEETING

May 17, 2017

Hilton at the Ballpark – St Louis, MO

• ATTENDANCE LIST •

Name	Company
Randy Lindstrom	NPPD
Dustin Betz	NPPD
Pat McGraf	KCPL
Harold Wyble	KCPL
Kurt Stradley	LES
Tim Owens	NPPD
Michael Wegner	ITC
Charles Hendrix	SPP
Jason Davis	SPP
Derek Brown	Westar
Kelsey Allen	SPP
Kirk Hall	SPP
Travis Hyde	OG+E

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ECONOMIC STUDIES/TRANSMISSION WORKING GROUP MEETING

May 17, 2017

Hilton at the Ballpark – St Louis, MO

• ATTENDANCE LIST •

Name	Company
Amber Greb	SPP
Walt Cecil	MoPSC
Rodney MASSMAN	MoPSC
Bethany King	EDE
Jeff Rooker	SPP RE
DON FRERKING	KCP&L
Scott Mijin	SWPA
Corey Falgout	AEP
Jason Bentz	AEP
JASON SHOOK	GDS/ETEC

All sessions in Central Daylight Time (Chicago, GMT-05:00)
Session detail for 'TWG Face to Face':

Participant	Name	Email
1	Dee Edmondson	dedmondson@spp.org
2	ed pfeiffer (quanta)	epfeiffer@quanta-technology.com
3	Randy Collier (CUS)	randy.collier@cityutilities.net
4	Kevin Foflygen (SPRM)	kevin.foflygen@cityutilities.net
5	Chris Matthes	camatthes@aep.com
6	Chris Jamieson - SPP	cjamieson@spp.org
7	Jeremy Harris (Westar)	jeremy.harris@westarenergy.com
8	Sam Zewdie	ss.zewdie@midwestreliability.org
9	Ryan Yokley	ryokley@sunflower.net
10	David Spargo	dpspargo@oppd.com
11	Richard Dahl (MRES)	richard.dahl@mrenergy.com
12	matthew stoltz	mstoltz@bepc.com
13	Kelsey Allen	kallen@spp.org
14	Evan Racine-Johnson GSEC	eracine-johnson@gsec.coop
15	Ben Abing	babing@itctransco.com
16	Clayton Mayfield	cmayfield@spp.org
17	Leon Howell	howelllc@oge.com
18	Jarrod Wolford (NTEC)	jwolford@ntecpower.com
19	John Fulton	john.fulton@xcelenergy.com
20	Jon Iverson	jiverson@oppd.com
21	Ashley Swain	aswain@spp.org
22	Steve Hardebeck-OGE	hardebsm@oge.com
23	Spp Staff	abarber@spp.org
24	Tim Owens (NPPD)	tjowens@nppd.com
25	James Bailey	jbailey@spp.org
26	Michael Mueller	michael.mueller@aecc.com
27	Bill Leung (NPRB)	bleung@bjleung.com
28	John Fernandes	jfernandes@invenergyllc.com
29	Bennie Weeks (SPS)	bennie.weeks@xcelenergy.com
30	Maureen Ochola	maureen.ochola@eon.com
31	Chenal WebEx	awhite@spp.org
32	Jamie Hajek	jamie.hajek@northwestern.com
33	Steve Hohman	shohman@oppd.com
34	John Payne (KEPCo)	jpayne@kepco.org
35	John Mayhan	jmayhan@oppd.com
36	Don Frerking (KCP&L)	don.frerking@kcpl.com
37	Michael Watt (OMPA)	mwatt@ompa.com
38	Jerry Bradshaw (SPRM)	jerry.bradshaw@cityutilities.net
39	Matt Waldron	mwaldron@atcllc.com
40	Adrienne Blaine	adrienne.blaine@wfec.com
41	Jason Mazigian	jmazigian@bepc.com
42	David Sargent	dave.sargent@swpa.gov

Kirk Hall

From: Boshears, John
Sent: Tuesday, May 16, 2017 10:07 AM
To: Kirk Hall; Bradshaw, Jerry; Knottek, Jeff
Subject: **External Email** Proxy

Kirk
I am giving Jerry Bradshaw my proxy

Sent from my iPhone

[City Utilities]

[City Utilities]<http://www.cityutilities.net>

PO Box 551 | Springfield, MO 65801-0551
cityutilities.net<http://www.cityutilities.net>

Kirk Hall

From:	Lenihan, Dan
Sent:	Tuesday, May 16, 2017 3:09 PM
To:	Kirk Hall
Cc:	Hyde, Travis; Verzal, Josh; SPARGO, DAVID P
Subject:	**External Email** OPPD TWG proxy for 5/17 meetings

Kirk,

I won't be able to make the joint TWG/MDWG meeting tomorrow morning (5/17), therefore, I'm submitting Dave Spargo of OPPD as my proxy for that meeting.

Also, it is likely that I will miss the joint TWG/ESWG meeting which follows the joint TWG/MDWG meeting. If I don't make it in time for the TWG/ESWG 5/17 meeting, Dave Spargo will be my proxy for that meeting as well.

Thanks,

Dan Lenihan, P.E.
Director – Planning & Strategy
Energy Delivery
Omaha Public Power District
Energy Control Center, ECC-5
Voice: (402) 552-5126 / (402) 636-2560
Email: djlenihan@oppd.com

From: Benson, Scott
Sent: Tuesday, May 16, 2017 3:45 PM
To: Kirk Hall
Cc: Hyde, Travis; Stradley, Kurt
Subject: **External Email** 5/17/17 TWG Proxy

Kirk,

I've had something come up back at LES and need to return tomorrow morning. Please accept Kurt Stradley as my voting proxy for the joint ESWG/TWG meeting tomorrow.

Thanks,

Scott J. Benson, P.E. | Manager, Resource & Transmission Planning
Lincoln Electric System
Phone: 402-473-3390
Fax: 402-473-3208
Email: sbenson@les.com
1040 O St.
PO Box 80869
Lincoln, NE 68501-0869
www.les.com

Kirk Hall

From: Severson, Jeremy
Sent: Wednesday, May 17, 2017 8:15 AM
To: Kelsey Allen; Myers, Alan
Cc: Stoltz, Matthew
Subject: **External Email** ESWG proxy

Hi Kelsey and Alan,

I would like to pass my proxy onto Matt Stoltz. I will be in and out of the meeting today as I am going be attending my daughters 5th grade track meet. I should be at most of the meeting but just in case I will pass the proxy to Matt in case a voting item comes up.

Regards,

Jeremy..

Kirk Hall

From:	Sharma, Anita
Sent:	Wednesday, May 10, 2017 7:38 PM
To:	Kelsey Allen
Cc:	Jacoby, Jim
Subject:	**External Email** ESWG Meetings May 17-18
Follow Up Flag:	Flag for follow up
Flag Status:	Flagged

Hello Kelsey,

Due to some prior work commitments that could not be changed, I am unable to attend the ESWG meetings next week and assign my proxy to Jim Jacoby.

Thanks
Anita Sharma
Principal Engineer
American Electric Power
614-753-5908

Kirk Hall

From:	Henderson, Natasha
Sent:	Wednesday, May 17, 2017 7:39 AM
To:	Kelsey Allen; Myers, Alan
Cc:	Evan Racine-Johnson
Subject:	**External Email** Proxy for ESWG 5/17-5/18

Evan will have my proxy for the next 2 days.

Natasha Henderson
Manager of Strategic Planning
Golden Spread Electric Cooperative
nhenderson@gsec.coop
(806)316-9581

"It is far better to foresee even without certainty than not to foresee at all."

--Henri Poincare

ITP Manual Outline

1. Introduction
    a. Purpose
    b. Overview of the SPP ITP Process
        i. Intro to ITP Process
        ii. History of the ITP
        iii. Organizational Group Support
            1. Working Group Ownership
        iv. TPITF
        v. ITP Process Today
    c. Study Scope Document
    d. Compliance with NERC TPL-001
2. Model Development
    a. Base Reliability Model
        i. Generation Forecasts
            1. Retirements
            2. Waiver Requests
        ii. Firm Transmission Service
        iii. Load Forecasts
        iv. Footprint
        v. Topology
            1. DC Ties
            2. DC Lines
            3. Phase Shifting Transformers
        vi. External Transactions
    b. SPP BA Economic Model Overview
        i. Model Assumptions and Data
            1. Futures Development
            2. Renewable Policy Review
            3. Load and Energy Forecasts
            4. Generation Resource Inclusion
            5. Generation Data
            6. Topology
                a. DC Ties and Lines
                b. Phase Shifting Transformers
            7. Fuel Prices
            8. Emission Prices
            9. Hurdle Rates
            10. Renewable Pricing
            11. Must Run Units
            12. Hydro Transactions
            13. SCUC & SCED Analysis
        ii. Resource Plan

1. Resource Expansion Plan
    a. Renewable Resource Expansion Plan
    b. Conventional Resource Expansion Plan
2. Resource Siting Plan
    a. Conventional Siting
    b. Wind Siting
    c. Solar Siting
3. Generator Outlet Facilities

iii. Constraint Assessment

c. SPP BA Powerflow Model Overview
    i. DC/AC Conversion
        1. Generation
        2. Topology
        3. DC Ties and Lines
        4. Phase Shifting Transformers
        5. Load Forecasts
        6. Resource Plan
        7. Generator Outlet Facilities
    ii. Reactive Device Settings
d. Operational Model Development
e. Interregional Coordination

3. Benchmarking
    a. Powerflow Model
    b. Economic Model
4. Needs Assessment
    a. Economic Needs Assessment
    b. Reliability Needs Assessment
    c. Public Policy Needs Assessment
    d. Persistent Operational Needs Assessment
    e. Short Circuit Needs Assessment
    f. Seams Needs
5. Solution Development and Evaluation
    a. Detailed Project Proposal (DPP) Process
        i. Solutions
            1. Transmission Projects
            2. Non-Transmission Solutions
            3. Model Corrections
            4. Operating Guides/Planning Guides
    b. Staff Solutions
    c. Cost Estimates
    d. Solution Evaluation Process
        i. Economic Solution Evaluation
        ii. Reliability Solution Evaluation
        iii. Public Policy Solution Evaluation

            iv. Persistent Operational Solution Evaluation
    e. Interregional Considerations
6. Portfolio Development
    a. Portfolio Development Methodologies
        i. Economic Portfolio Development
        ii. Reliability Portfolio Development
        iii. Public Policy Portfolio Development
        iv. Persistent Operational Portfolio Development
        v. Portfolio Synergy
    b. Consolidation
    c. Project Staging
        i. Economic Projects
        ii. Reliability Projects
        iii. Public Policy Projects
        iv. Persistent Operational Projects
    d. Final Assessments
        i. Benefit Metrics
        ii. Sensitivity Analysis
        iii. Final Reliability Assessment
            1. Stability Assessment
7. Deliverables
    a. Final Report
8. Issuance of NTCs
9. Staff and Stakeholder Accountability
    a. Revision Request Process
    b. Accountability Process
10. Appendices
    a. Glossary

ITP MANUAL

Subtitle

Published on DATE

By AUTHOR/DEPARTMENT

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
02/3/2017	Communications Department	Document created	
3/23/2017	Communications Department	Sections added, changes made to document layout	
4/17/2017	Communications Department	Sections added, changes made to document layout	
5/3/17	Communications Department	Sections added, changes made to document layout	

CONTENTS

INTRODUCTION

PURPOSE

The SPP Open Access Transmission Tariff (OATT), Attachment O Section III.8.e, requires Southwest Power Pool, Inc. (SPP) to assess the cost effectiveness of proposed transmission projects in accordance with the Integrated Transmission Planning (ITP) Manual. This manual will outline the processes for the annual ITP process.

The ITP is a regional planning process built to leverage knowledge of the transmission system's reliability, public policy, compliance, and economic needs, as well as generation interconnection and transmission service request impacts in order to develop a cost-effective transmission portfolio over a 10-year planning horizon. Utilizing a common set of foundational modeling assumptions as the starting point for all planning studies within the planning cycle, the model builds for all reliability, public policy, compliance, and economic studies will be developed to produce needs assessments for two, five and 10-year planning horizons. System needs resulting from generation interconnection and transmission service requests will be identified within the currently established timelines for those processes. However, the evaluation of transmission service needs and associated projects will be coordinated with those identified in the 10-year horizon regional planning process to facilitate continuity in the overall transmission expansion plan. This targeted approach is both forward-looking and proactive, designing a cost-effective and responsive transmission network which adheres to the ITP principles (listed in section 1.B), while following the FERC "Nine Transmission Principles".[1]

Analyses will be performed following the adoption of the study assumptions and will focus on cost-effectiveness and flexibility, while taking into account reliability, public policy, compliance, and economic considerations in project or portfolio recommendations. In the assessment of a project or group of projects' performance, SPP will assess the project's ability to perform across multiple capacities, which may include:

- Performance across multiple futures
- Ability to solve multiple Need types
- Reliability impacts related to compliance with NERC Standard TPL-001-4
- Operational impacts

Cost-effective analysis is a form of economic analysis that allows for the most effective planning over a longer versus shorter-term time frame. The objective is to produce the most economical project planning over the longer-term horizon.

This manual includes standardized language detailing ITP study items that were reviewed by the appropriate stakeholder groups and approved by MOPC. This standardization will provide specific details around each scope item and eliminate the need for repetitive reviews and approvals in order to help facilitate the performance of an annual planning cycle. Stakeholders will retain the ability to request a modification of standardized scope items by utilizing the SPP revision request

[1] These FERC principles are coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning (congestion) studies, and cost allocation for new projects, as described more fully in Order 890, Final Rule, pages 245 – 323.

(RR) process as discussed in more detail below. An ITP study scope will be developed for items that will require stakeholder review and approval with each new study. The ITP manual, study scope, and RR process are described further in later sections of this manual.

OVERVIEW OF THE SPP ITP PROCESS

INTRO TO ITP PROCESS

The ITP process is SPP's approach to planning transmission needed to maintain reliability, provide economic benefits and achieve public policy goals for the SPP region in both the near and long-term horizons. The ITP process enables SPP and its stakeholders to facilitate the development of a reliable and flexible transmission grid that provides regional customers improved access to the SPP region's diverse resources.

The ITP process assesses transmission and operational needs over a 10-year horizon and is designed to produce an annual report. It is designed to create synergies by integrating SPP transmission planning activities that incorporate reliability, economic, policy and compliance components in the overall assessment of the transmission grid. The ITP process works in concert with SPP's existing sub-regional planning stakeholder process, and parallels the North American Electric Reliability Corporation (NERC) transmission planning reliability standards compliance process.

HISTORY OF THE ITP

In January 2009, the SPP Board of Directors (BOD) created the Synergistic Planning Project Team (SPPT) to address gaps and conflicts in SPP's transmission planning processes; to develop a holistic, proactive approach to planning that optimizes individual processes; and to position SPP to respond to national energy priorities.

The SPPT recommended that the organization adopt a new set of planning principles; develop and implement an ITP process; develop a plan to monitor the construction of projects approved through the ITP process; and identify priority projects that continue to appear in system reviews to relieve congestion on existing constraints and connect SPP's eastern and western regions. The SPPT recommended that the Regional State Committee (RSC) establish a "highway-byway" cost allocation methodology for approved projects.[2]

The SPPT created the following principles to drive development of the ITP process:

- Focus on regional needs while also considering local needs; long-range plans (both ITP20 and ITP10) are to be updated every three years while ITP Near-Term plans are to be updated annually.
- Plan the backbone transmission system to serve SPP load with SPP resources in a cost-effective manner. The transmission backbone will:
    - Enhance interconnections between SPP's western and eastern regions
    - Strengthen existing ties to the Eastern Interconnection.

[2] The highway-byway cost allocation was approved by FERC on June 17, 2010. http://elibrary.ferc.gov/idmws/nvcommon/NVintf.asp?slcfilelist=12369183:0

  - Provide options for planning and coordination to the Western Electricity Coordinating Council (WECC) and the Electric Reliability Council of Texas (ERCOT) grids in the future.
- Incorporate 20-year physical modeling and 40-year financial analysis timeframes.
- Better position SPP to proactively prepare for and respond to national priorities while providing flexibility to adjust expansion plans.
-

SPP began performing its planning duties in accordance with the ITP process in January of 2010.

ORGANIZATIONAL GROUP SUPPORT

The ESWG identifies and maintains the economic data, data sources, models, economic planning methodology and processes and metrics to be used in the evaluation of economic expansion needs in the SPP region.

The TWG oversees and maintains the study processes for reliability and compliance to be used in the evaluation of reliability expansion needs in the SPP region.

The Operating Reliability Working Group (ORWG) identifies and maintains operational data, data sources and models to be used in the evaluation of persistent operational expansion needs in the SPP region.

The ORWG, TWG and ESWG are responsible for the process of identifying needs associated with persistent operational issues.

ITP recommendations are reviewed and may be endorsed by ESWG, TWG and MOPC.
Those recommendations approved by the board will allow staff to issue Notification To Construct (NTC), Notification To Construct-Conditional (NTC-C), or Request For Proposals (RFP) for approved competitive projects letters for projects needed within the financial commitment horizon.

THE TRANSMISSION PLANNING IMPROVEMENT TASK FORCE

In February 2015, the Transmission Planning Improvement Task Force (TPITF) was assembled by the SPP Strategic Planning Committee (SPC) and the MOPC and given the responsibility for developing recommendations to improve the regional planning processes. Their objective was to make the SPP transmission planning process more responsive to the effects of the continued growth of SPP's transmission system, changes in the SPP markets, challenges and opportunities presented by changing federal and state energy and environmental regulations and increasing NERC compliance requirements. The TPITF recommendations were intended to represent a consolidated, coordinated approach in planning, managing and maintaining the SPP transmission system, with a particular emphasis on increasing the availability of transmission service to SPP's customers without unduly compromising system reliability. The recommendations in the TPITF whitepaper were intended to enable the cost-effective use of capital-intensive generating resources for the benefit of all end-use customers in the SPP footprint and to further develop and enhance policies, tools and practices to optimize the use of the transmission system. The TPITF was tasked with reviewing, evaluating and proposing recommendations on the following:

1. The methodologies and modeling practices used in the generator interconnection studies; aggregate transmission service studies; integrated transmission planning (near-term, 10, and 20); SPP TPL compliance assessments; and the MDWG model development process to

ensure effectiveness, consistency and to determine if gaps exist between the various processes.

2. The utilization of data, including data collected by operations, which will benchmark the real-time and planning horizon assessments to ensure consistency in the planning process.
3. The appropriateness of the planning cycle and assessments, including the effectiveness of using production-cost modeling in more assessments; development, use, and weighting of futures, scenarios and sensitivities; and the metrics used to evaluate proposed projects, in particular those that evaluate the impact on rate payers, and planning the transmission system beyond the traditional planning criteria of first contingency ("N-1") in accordance with the approved NERC Standard TPL-001-4.

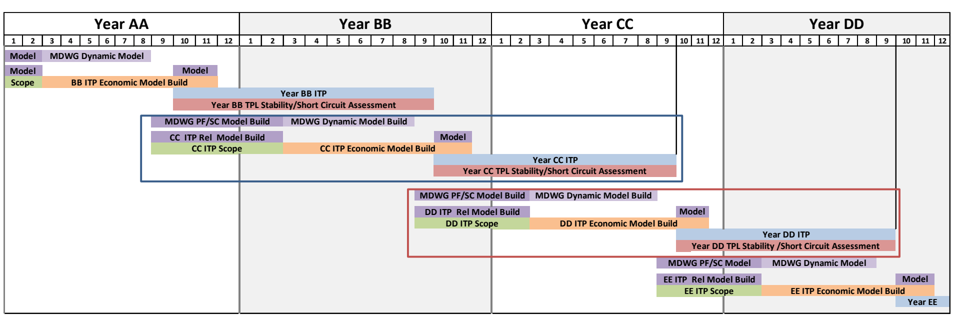
The TPITF developed five recommendations to accomplish this scope of work that are discussed in detail throughout this manual. These five recommendations were as follows.

1. Replace the current three-year ITP assessment cycle with an annual planning cycle
2. Create a standardized scope[3][4]
3. Establish a common-base reliability model for use across the various SPP planning processes
4. Utilize a holistic planning process
5. Create staff/stakeholder accountability for the timely exchanges of data, reviews and approvals within the transmission planning process

Commented [MDS1]: Hyperlink

ITP PROCESS TODAY

In July 2016, the MOPC, BOD and the SPC approved the recommendation of the TPITF to replace the three-year ITP study cycle with an annual planning cycle. The recommendation included removal of the ITP20 assessment from the planning process and combining of the ITPNT and ITP10 assessments into an annual, 10-year study. The annual assessment will also incorporate the TPL-001-4 short circuit and portions of the TPL-001-4 steady-state assessments. The annual ITP study will assess years two, five, and 10 for reliability, public policy, compliance and economic needs.



[3] The standardized scope is referred to as the ITP manual in this document.
[4] The previous ITP manual can be found on the SPP webpage.

The planning cycle, as illustrated above, will consist of scope development and model build for approximately 12 months and a planning assessment period of approximately 12 months. The scope development and model build for the succeeding cycle will begin concurrently with the planning assessment period of the preceding study resulting in a 12-month overlap that will produce a report annually at the completion of each cycle. This annual planning cycle will iterate in this fashion going forward producing an annual, integrated transmission planning report and list of recommended projects.

Successful implementation of the ITP process will result in a list of transmission expansion projects, projected project costs and completion dates that facilitate the creation of a cost-effective, reliable, flexible and responsive transmission network in the SPP footprint.

COMPLIANCE WITH NERC TPL-001-4

STUDY SCOPE DOCUMENT

In order to provide the appropriate context under which to assess the future performance of the existing transmission system and any needed improvements, certain assumptions and methodologies may change with each study cycle. Maintaining the ability to update these assumptions from study to study will provide the flexibility needed for the transmission planning process. The Study Scope document describes those items that will require Stakeholder review and approval with each new study. Those study scope items will be approved by the appropriate working groups during the scope development phase at the beginning of each planning cycle.

MODEL DEVELOPMENT

The table below lists the model sets for the ITP planning cycle. More information on these models can be found in the subsections to follow.

The ITP model set consists of the following:

Description	Year 2	Year 5	Year 10	Total
Base Reliability[1] (TPL[2] Base Case)	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	9
SPP BA (Economic)	One Future (1)	Each Future (1-3)	Each Future (1-3)	3-7
SPP BA Powerflow (Reliability)	One Future's Peak and Off-Peak (2)	Each Futures' Peak and Off-Peak (2-6)	Each Futures' Peak and Off-Peak (2-6)	10-14

(TPL[2] Sensitivity Case)				

Table 1: ITP model set[5]

Base Reliability Model Scenario
Each of the base reliability models will be an indicative representation of how entities within SPP responsible for serving network load would do so utilizing network resources only. These models would consist of non-coincident peak load forecasts, assumed long-term firm transmission service usage levels and expected conventional and renewable resource output levels.

Commented [AG2]: Add to definitions appendix

SPP BA Economic Model
Each SPP BA economic model simulation is an hourly security constrained unit commitment and economic dispatch utilizing a DC representation of the transmission system.
A single economic model will be built for year two, reflective of only the reference case future. For each of the futures, a year five and year 10 economic model will be developed. The assumptions for each of the economic models will be described in detail later in this section.

SPP BA Powerflow Model Scenario
Each SPP BA powerflow model is an AC powerflow representation of a specific one-hour snapshot of an economic model run with SPP acting as its own balancing authority. Each SPP BA economic model built will have two AC powerflow models developed based upon system conditions of a single hour within the year. The two hours represented will be the SPP coincident summer peak hour (peak) and the hour with the highest wind penetration between April and May (off-peak). The models will be built by matching the dispatch in each powerflow model to the dispatch in the respective hour of the economic model simulations. This process will be described later in the DC/AC conversion process. Once the model is finalized, staff and stakeholders will assess reactive powerflows on the system that the economic modeling tools are unable to represent. Some of the SPP BA powerflow models will be used to meet the requirements of a sensitivity case necessary for TPL-001 compliance.

Commented [KH3]: If we have a Definitions piece to the manual we should include the NERC definition of BA there

Commented [KH4]: Currently still a staff recommendation. This is still up for discussion with the WGs. If this recommendation changes the language will be updated accordingly.

BASE RELIABILITY MODEL

As previously discussed within this manual, the ITP process will be used to satisfy the planning requirements found in Attachment O of the SPP OATT, as well as some NERC Compliance requirements within NERC Standard TPL-001 (TPL) using a common planning model scenario (Base Reliability Model). This scenario will be built consistently with the information found in the following sections of this manual. Nine (9) total power flow models will be built using the methodology of the common planning model. The table below describes the years and seasons that will be developed by SPP.

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[5] The base reliability model set listed and described above is the base model set for all of SPP's planning processes including transmission service, generation interconnection and compliance studies.
[2] The details on the models and the process that will be used for TPL-001 compliance will be documented in the TPL-001 scope document.

Year Two	Year Five	Year 10
Summer Peak	Summer Peak	Summer Peak
Winter Peak	Winter Peak	Winter Peak
Light Load	Light Load	Light Load

This model set will be utilized as the base model for transmission service and generator interconnection study processes. It is important to note, however, these base scenario models will be adjusted as necessary within each individual process to appropriately analyze and integrate transmission service requests or generator interconnection requests consistent with the SPP Tariff provisions and business practices that govern each process.

Information needed to construct the models will be provided by SPP members with appropriate review opportunities by SPP staff and stakeholders, prior to receiving final approval. These inputs, described in the following sections, include:

- Generation Resources
- Load Forecasts
- Definition of the SPP Footprint
- Topology
- Modeling of Firm-Transmission Service
- DC Tie Modeling
- DC Line Modeling
- Phase Shifting Transformers
- NTC Re-evaluation Requests

All data requests and review opportunities will be administered through the Model Development Working Group (MDWG) and Transmission Working Group (TWG), as appropriate.

Additionally, a short circuit model will be built for the short circuit assessment to meet short circuit analysis required in the TPL standard. This short circuit model will be built under the guidance of the Model Development Working Group (MDWG).

GENERATION FORECASTS

Retirements

Waiver Requests

LOAD FORECASTS

The ITP process will require load forecasts for SPP members and non-members within the SPP footprint, as well as areas outside of the SPP footprint, for the corresponding study years. The load forecast will be submitted to the MDWG using the process described in the MDWG manual model building process.

The load will represent each individual load balancing area's peak conditions without losses per season (*i.e.*, non-coincident conditions for the SPP region).

FOOTPRINT

The modeling footprint includes the entire SPP region and nearby areas within the Eastern Interconnection. The non-SPP areas that may be modeled are AECI, Midwest ISO, and the western portions of PJM and SERC.

In the event of pending changes in the footprint of a region, additional areas may be added and additional sensitivities or scenarios may be studied in order to properly assess, anticipate, and understand the impact of such changes on the transmission needs of the SPP. These would be identified in the study scope.

TOPOLOGY

Firm Transmission Service

DC Ties

DC Lines

Phase Shifting Transformers

SPP BA ECONOMIC MODEL OVERVIEW

MODEL ASSUMPTIONS AND DATA

Future Development

Due to the uncertainties involved in forecasting future system conditions, a number of diverse futures are considered that take different assumptions into account. Consideration of multiple futures provides for a transmission expansion plan that is sufficiently flexible to meet a variety of needs that may develop as economic, environmental, regulatory, public policy and technological changes arise that affect the industry. The futures will be developed by the ESWG with input from the Strategic Planning Committee (SPC) and the Transmission Working Group (TWG), and subject to the approval of the MOPC.

Economic models will be developed for three study years (years two, five, and 10). A single future will be developed for year two, due to the limited uncertainty in policy or other factors impacting the system that could occur in such a short time frame. Up to three futures will be developed for years five and 10, during the scoping of each successive annual assessment. The futures will consist of a reference case, as determined by the ITP study scope, along with one or two additional futures designed to assimilate expected or plausible future scenarios. Details around the reference case and the future case(s) will be included in the ITP study scope document. As a result, up to seven total economic models may be developed to support economic assessments.

During the development of the futures, SPP staff will solicit stakeholders for potential public policy drivers to be considered in the study. The time, place and method for the submission of public policy drivers that stakeholders request to be considered shall be included in the study schedule. A list of those drivers requested to be considered by stakeholders that are excluded from the study as well as an explanation for the exclusion shall be detailed in the ITP study report.

Renewable Policy Review

After the forecasted load is finalized, renewable policy standards (RPS) will be assessed for utilities within the SPP footprint. The percentages in table XX will be used to calculate the mandate or goal for each utility residing in the listed states with respect to the load submitted as part of the SPP annual data request. For those utilities that span multiple states, the approved powerflow models and geographical information system (GIS) data will be used to calculate each utility's load obligation in the corresponding state for purposes of calculating mandates and goals.

The values in table XX consider forward-looking legislation set by the states that should be met in each of the study years. A generation type of "both" indicates the mandate or goal can be met by either wind or solar generation in the study. Both capacity-based and energy-based mandates and goals will be assessed for fulfillment during the resource plan; those that are energy-based will also be assessed during the policy needs assessment. States within the SPP footprint that are not included in table XX shall be presumed to have no RPS requirement for the purposes of this renewable policy review.

State	RPS Type	Generation Type	Capacity- or Energy- Based	Year 2 %	Year 5 %	Year 10 %
Kansas	Goal	Both	Capacity	20	20	20
Minnesota	Mandate	Both	Energy	20	20	25
Missouri	Mandate	Both	Energy	15	15	15
Montana	Mandate	Both	Energy	15	15	15
North Dakota	Goal	Both	Energy	10	10	10
New Mexico	Mandate	Wind	Energy	15	15	15
New Mexico	Mandate	Solar	Energy	4	4	4
South Dakota	Goal	Both	Energy	10	10	10
Texas	Mandate	Both	Capacity	5	5	5

Renewable Energy Credits (REC) will be appropriately accommodated as provided to SPP staff.

If any significant changes to renewable mandates or goals occur during an ITP assessment, stakeholders can bring them to the ESWG for review and potential approval for use in the ITP assessment. If exemptions to the mandates or goals are allowed (e.g. the applicable technology is cost prohibitive or municipals are exempt), those exemptions will be considered as SPP staff is notified during the renewable policy review.

Any resulting deviations from the standard values in table XX will be noted in the corresponding study report.

Load and Energy Forecasts

The ITP process will require load forecasts for areas within and outside the SPP footprint for each of the study years.

The load will represent each individual load-balancing area's peak conditions without losses per season (*i.e.*, non-coincident peak conditions for the SPP region). Resource obligations will be determined for the footprint taking into consideration non-scalable and scalable loads.

For the economic model build process, SPP staff will obtain load data to utilize in the ITP process by the following:

- Peak Load: The source shall be the no-loss aggregated bus load totals (MW) based on the current base reliability models.
- Hourly Load Shape: The primary source shall be vendor data. If the primary source is not available, SPP staff will create a synthetic load shape based off of historical data points and FERC Form 714.
- Monthly Peak and Energy Percentages: The primary source shall be vendor data. If the primary source is not available, SPP staff will calculate the monthly peak and energy percentages by using hourly load shape data.
- Load Factor: The primary source shall be for stakeholders to provide annual load factors. If the primary source is not available, SPP staff will calculate load factors by utilizing hourly load shapes.
- Transmission Loss Factor: The primary source shall be for stakeholders to provide annual loss factors. If the primary source is not available, SPP staff will utilize previous ITP study values.
- Demand Group Bus Mapping: The primary source shall be for the SPP staff load ownership identification processes to assign load to powerflow areas and demand groups. If the primary source is not available, stakeholders will provide load bus and ID mappings to powerbase demand groups.

External region load forecasts will be taken from the latest MDWG/MMWG powerflow model and each region will be allowed to review load forecast data prior to using in the ITP processes. If readily available and Staff and Stakeholders find it appropriate, load forecasts from the most current neighboring entity's study will be used for their region in the ITP in place of the Model Development Working Group (MDWG)/MMWG powerflow data. The use of their load forecast is future-specific; if there is not a future comparable to the ITP future, as determined by staff and the

Economic Studies Working Group, the load forecast would be determined utilizing MDWG/MMWG powerflow data. This process will be documented in the study scope.

Generation Resource Inclusion

Generation resources included in the base reliability model will be incorporated into the economic model, as appropriate.[6] Resources identified by SPP staff as necessary in order to develop the base reliability model shall not be included in the economic and powerflow models, unless the resources meet the requirements of adding generation described below.

Incremental to the resources included in the base reliability models, a generation interconnection resource and its associated network upgrades will be included in the economic models if they meet all of the following requirements:

- A formal request has been sent to SPP[7] requesting the generation capacity be included
- The generating resource has a FERC-filed interconnection agreement (IA) not on suspension or FERC-filed interim IA
- The generating resource will have a firm contract for delivery through ownership and operation of the resource or procurement of a purchase power agreement (PPA) from the generation owner.

If a generating resource does not meet all the above requirements, a request for generation capacity to be included in the economic models can be made to ESWG and TWG on a case-by-case basis. ESWG and TWG will take into account the following, but not limited to, additional points:

- A Definitive Interconnection System Impact Study Agreement (DISIS) for the generating resource has been executed, an interim IA has been requested and a final IA will be FERC filed, when applicable
- An RFP for the generating resource has been awarded, if applicable

All other resource expansion needs will be determined through the SPP resource expansion planning process as detailed in the Resource Expansion Plan section.

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Generation in the Economic Model

Vendor data will be used as the starting point for generation parameters needed for production cost modeling. Data related to the physical characteristics of generators will be reviewed and updated as needed by the stakeholders to provide company-specific values through the SPP annual data request.

The vendor data to be utilized as a starting point may include:

- Generator name

[6] Generally, smaller resources that are not included in the economic data supplied by the vendor but are modeled in the powerflow are not included in the economic model for consideration in the production cost simulation. Examples are units reported publically as behind the meter or small municipal generation.

[7] Email sent to EconomicPlanning@spp.org

- Category type
- Conventional variable operation & maintenance (VOM)
- Conventional fixed operation & maintenance (FOM)
- Heat rate
- Heat rate profile
- Physical state location
- Annual maintenance hours
- Forced outage rate
- Effluents (percentage removed)
- Emission rates
- Fuel forecast
- Hydro energy limits
- Seasonal max capacity by year
- Retirement date
- Commission date
- Must run designation

Generation Data

Topology

The topology used in the economic models to account for the transmission system of SPP and external entities will follow the same guidelines detailed in the Common Scenario Planning Model Overview Topology section for the base reliability model with a few exceptions:

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- The topology utilized for each study year's annual simulation will be based on the summer peak base reliability model developed for that year,
- Long-term transmission outages of six months or greater modeled in the base reliability model will not be included for the purposes of the economic model.

DC Ties and Lines

Phase Shifting Transformers

Modeling parameters for phase shifting transformers will be determined leveraging data from:

1) Historical and/or current operating practices, and
2) Powerflow modeling.

The specific modeling of the phase shifting transformers will be detailed in the study scope.

Fuel Prices

Fuel price forecasts for the reference case future including natural gas, oil, uranium, and coal, including transportation costs, will be based upon the latest vendor data set.

Potential adjustments to the fuel prices for the non-reference case future(s) will be determined by the ESWG to appropriately reflect each future, and will be described in the ITP study scope document.

Emission Prices

Emission price forecasts for the reference case future including, but not limited to, CO_2, SO_2, and NO_X will be based upon the latest vendor data set.

Potential adjustments to the emission prices for the non-reference case future(s) will be determined by the ESWG to appropriately reflect each future, and will be described in the ITP study scope document.

Hurdle Rates

Hurdle rates for all futures will be based upon the latest vendor data set. Potential adjustments to the hurdle rates will be determined by the ESWG, and will be described in the ITP study scope document.

Renewable Pricing

The economic modeling of wind and solar resources include two primary parameters that impact pricing: curtailment price and VOM.

Wind and solar resources include an hourly profile. The curtailment price for wind and solar is the trigger price at which the resource will curtail. If the LMP at the generation bus is greater than or equal to the curtailment price, the unit will generate energy in accordance with the hourly profile. If the LMP at the generation bus is less than the curtailment price, the unit generation will be curtailed. As a result, the curtailment price parameters impact the dispatch of wind and solar units in the economic modeling but does not impact the operating cost of the units.

In order to model a curtailment price for wind units that will reflect market operation, including projected Production Tax Credit (PTC) impacts, the following criteria will be used for wind curtailment price modeling:

- Wind units will have $0/MWh curtailment price if any of the following are true[8]:
    - The unit is placed in service over 10 years prior to the study year
    - Construction on the unit has not started prior to January 1, 2020
    - An entity has provided feedback that the Investment Tax Credit (ITC), rather than PTC, is applicable
- Otherwise, wind units will have a -$35/MWh curtailment price to reflect the "grossed-up" value of a PTC[9].

The VOM for wind and solar resources defines the unit operating cost per MWh of energy generated. This operating cost is used in adjusted production cost (APC) calculations. The VOM parameter does not impact dispatch, curtailment or LMPs in the economic model simulations.

In order to reflect power purchase agreement (PPA) pricing as part of the VOM, the following criteria will be used for VOM modeling:

[8] Reflecting that the PTC is not a factor in its operation
[9] For income tax compensation

- The SPP annual data request process for generation shall include reporting of the wind and solar units which have fixed-contract prices, such as PPAs. Staff will request appropriate documentation of units reported; if documentation is provided, the variable O&M of the unit shall be based on approximate wind and solar fixed-contract pricing, derived from publicly available data. A weighted average of the most recent five to 10 year period shall be used.
- For all wind and solar units in which appropriate documentation is not provided to staff, the variable O&M of the unit shall be $8/MWh to reflect the low operating cost of renewable resources.
- For wind or solar units identified through the resource expansion plan, the variable O&M of the new unit shall be equal to the variable O&M of the majority of existing wind or solar units in the model
    - Example: If 80 percent of existing wind units have the fixed-contract price for VOM, new wind units would use the fixed-contract price for VOM.

Must Run Units

Must-run units in ITP studies are dispatched during all available hours to at least their minimum capacity states, regardless of economics. Must-run statuses will be removed from all units at the start of each study. In the development of the ITP study scope, the ESWG will determine if must-run units will be allowed and the criteria needed for such designation. Individual generating units meeting must-run criteria will be submitted by staff or stakeholders during the generation review and subject to approval by the ESWG.

Hydro Transactions

SCUC & SCED Analysis

An economic assessment will be performed to analyze congested facilities on the SPP transmission system. The economic needs of the system will be identified in order to develop a portfolio for each future. All of the economic system needs will be identified through the use of a Security Constrained Unit Commitment (SCUC)/Security Constrained Economic Dispatch (SCED) simulation that accounts for every hour of the study years. The SCUC/ SCED simulation requires a dual-optimization process. The first process is the SCUC. Here, the hourly least-cost combination of units that should be committed (turned on or off) is determined subject to unit-specific operational constraints (e.g., ramping, minimum output, min/max runtime, startup cost, etc.), and some critical location-specific transmission reliability constraints (e.g., must-run operational limits); but without explicit consideration of transmission grid operational costs.

The second process is the SCED solution of the units committed by the SCUC process. In the SCED process, the units are dispatched (exact unit output determined) in a least-cost manner subject to various transmission operational constraints (e.g., line thermal limits) and transmission reliability constraints (e.g., n-1 contingencies).

The SCUC and SCED model will solve using nodal Locational Marginal Prices (LMP), which will commit and dispatch the generation economically based on unit characteristics, load information, and transmission constraints. These analyses will determine potential issues including congestion, LMP variation, and trapped generation.

RESOURCE PLAN

Resource Expansion Plan

After forecasted load and existing and planned generation have been defined through the SPP annual data request schedule, analysis will be conducted to determine new (conventional and renewable) resource additions required in years five and 10, for each future in the economic and SPP BA powerflow model. Resource additions are included in order to develop realistic future year models, by accounting for reserve margin requirements, historical trends, economics, etc. The resource-planning phase will identify new units and the associated parameters for these new units, but will not include any siting considerations, which will be addressed in the Resource Siting Plan section.

The year two models will be assessed to evaluate whether the reserve margin requirements are being met at the SPP BA level.

Renewable Resource Expansion Plan

SPP staff and the ESWG shall develop the criteria for renewable additions, as documented in each study, with consideration of the futures being studied and of factors such as government regulations, the renewable policy review, historical trends, natural gas prices, installation trends, IRP projections and stakeholder feedback.

Renewable additions will be computed using criteria that can be applied uniformly across pricing zones[10] (for example, each pricing zone shall have renewable capacity of at least a certain percentage of their annual peak load responsibility). Renewable resources other than wind and solar (such as biomass) shall only be added to the model as defined in the Generation Resource Inclusion and Generation Resources sections.

External regions and areas that are economically dispatched in the model may include renewable additions beyond the units planned at the time of study. These renewable additions shall be determined by staff and the ESWG in each study based on consideration of the futures being studied and of factors such as government regulations, historical trends, natural gas prices, installation trends (nation-wide and location-specific), IRP projections, and feedback from external entities.

The exception to this methodology is that an appropriate resource plan from the most current neighboring entity's study will be used for their region in the ITP, if readily available and staff and stakeholders find it appropriate. The use of their resource plan is future-specific; if there is not a future comparable to the ITP future, as determined by staff and the ESWG, then renewable additions would be determined in the same manner as other external regions.

[10] Renewables are not necessarily sited within the pricing zone, but pricing zones can be assigned ownership of the renewable generation

Conventional Resource Expansion Plan

The conventional resource expansion plan process begins with the identification of a publicly available source for new generation prototype parameters, which shall be documented in the study scope.

Each pricing zone shall be assessed for resource adequacy by accounting for load projections, existing generation, new wind and solar additions, capacity accreditation for all renewable units, fleet PPAs and DC tie accreditations. Each pricing zone's resource shortfall shall be computed based on the SPP reserve margin requirement currently in effect.

Resource expansion software will be used in all futures to identify the optimum mix of new conventional resource additions needed for the region[11]. The magnitude of resource additions will be based on resource shortfalls. Conventional unit additions selected by the software tool will be allocated to pricing zones such that each pricing zone approximately meets the reserve margin requirement. Joint ownership of unit additions may be used in order to avoid excessive additions of new resources to individual pricing zones.

External regions will also be analyzed for resource shortfalls. To address shortfalls, conventional resources shall be added to external regions with a resource mix that is as close as possible to the SPP conventional resource addition mix for that future. For example, if SPP conventional resource additions include 60 percent CCs and 40 percent CTs, a ratio as close as possible to this 60/40 ratio would be used to guide conventional resource additions in external regions.

The exception to this methodology is that an appropriate resource plan from the most current neighboring entity's study will be used for their region in the ITP, if readily available and staff and stakeholders find it appropriate. The use of their resource plan is future-specific; if there is not a future comparable to the ITP future, as determined by staff and the ESWG, then conventional additions would be determined in the same manner as other external regions.

[11] Resource expansion software is not currently adequate for identifying new renewable resources. As resource expansion software improves, SPP may incorporate renewable resources additions in the software as an additional factor for consideration.

Resource Siting Plan

Conventional Siting

Wind Siting

Solar Siting

Generation Outlet Facilities

CONSTRAINT ASSESSMENT

SPP BA POWERFLOW MODEL OVERVIEW

DA/AC CONVERSION

Generation

Topology

DC Ties and Lines

Phase Shifting Transformers

Load Forecasts

Resource Plan

Generator Outlet Facilities

REACTIVE DEVICE SETTINGS

After the DC/AC conversion process is complete, an opportunity will be provided for staff and stakeholders to review the settings for transmission facilities that provide reactive support for the transmission system. Stakeholders will be asked to submit changes to set points for capacitors and reactors, tap changers for transformers, and remote buses and voltage schedules for generators and Static Var Compensators. These adjustments will improve the response of the transmission system under system intact and contingency conditions as well as provide confidence to both staff and stakeholders that potential violations are realistic system conditions prior to the reliability needs assessment.

No topology changes will be accepted to correct the model. Any identified model corrections will be required to be submitted during the Detailed Project Proposal (DPP) window as outlined in Section 5.

Once all reactive device settings have been received, staff will apply the adjustments to the appropriate models before final posting and approval by the TWG.

OPERATIONAL MODEL DEVELOPMENT

BENCHMARKING

POWERFLOW MODEL

A year 0 powerflow model will be utilized to validate that modeling parameters are reflective of the SPP operations. Operations data validation may include a comparison of topology and ratings. Further benchmarking will occur against the previous study models and may include a comparison of the following: topology, generation, load, ratings, transmission service and area interchange.

ECONOMIC MODEL

The year two study assessment model will be utilized to validate modeling parameters to determine if operation is reflective of the SPP system. Data validation may include the following: capacity factor by unit type, maintenance outages, operating and spinning reserves, average cost per MWH, system LMPs (zonal, average, max, etc.), interchange, APC comparison and renewable generation profiles. Data may be compared to the most recent SPP operational data and previous study models.

NEEDS ASSESSMENT

ECONOMIC NEEDS ASSESSMENT

The economic needs assessment will be performed parallel to the reliability and policy needs assessments. The economic needs of the system will be identified for each future and study year. Economic model simulation derives nodal LMPs by dispatching generation economically while honoring the transmission constraints defined for the system. LMPs reflect the congestion occurring on the transmission system's binding or breaching constraints. The simulation results will reveal constraints causing the most congestion and additional cost of dispatching around those constraints. This is the starting point for constraints to be considered for economic needs for the study.

The following process will be used to filter and rank the congested constraints of each future and study year to target a list of economic needs for the study:

1. Binding constraints will be ranked from highest to lowest congestion score. Congestion score is defined as the product of the constraint's average shadow price and the number of hours the constraint is binding.

Figure: congestion score

2. A list of binding constraints will be reduced to the congested flowgates that have greater than $50,000/MW in annual flowgate congestion score. However, SPP staff may include additional constraints if staff believe the inclusion would better define an economic need overall.[12]

3. Constraints with monitored elements not interconnected with the SPP transmission system that provide less than $1 million in annual potential benefit to SPP will be removed unless SPP staff determines that the constraints are related to a target area or a historically congested Market to Market flowgate and warrant further analysis.[13]

[12] As an example, the most congested, unique, monitored element and other constraints with the same monitored element would only be considered one need.Each additional constraint included would better define the economic need overall.

[13] Potential benefit is determined by relaxing the rating of the monitored element of a flowgate to relieve congestion.

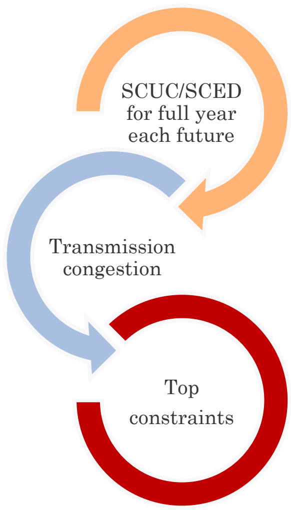


Figure: developing economic needs

The constraints list will be condensed by identifying the target areas (top areas of known or forecasted congestion) in order to more efficiently focus the combined efforts of SPP staff and stakeholders to identify the most valuable solutions. In addition to using congestion scores to rank constraints, SPP staff may also include additional information, such as the relationship of constraints to:

- Each other
- Integrated market congestion[14]
- Operational issues
- RCAR issues
- Seams issues
- Operational, reliability and/or policy needs
- Generation interconnection and transmission service study queue limitations
- Transmission corridors with limited capacity
- PTDF flowgates used to represent thermal, stability or contractual limitations
- Facilities that are thermally limited by terminal equipment

SPP staff will provide general explanations and rationale surrounding additional information and grouping of constraints as well as high-level scopes for any additional analysis to be performed on constraints and/or target areas in developing a recommended portfolio of projects.

[14] Staff will relate the economic needs to historic congestion in the SPP Integrated Marketplace and external markets as reported in quarterly and annual market monitor reports.

The use of engineering judgment may be needed in order to meet the study schedule and considering the study scope. If necessary, it may limit the number of needs by future by year depending on the number of binding constraints with similar attributes, recommended constraints and/or target areas for additional analysis, mitigation need dates, general transmission solution lead times and other project staging considerations.

In the analysis portion of this milestone, all needs will be reviewed to understand the underlying study assumption drivers. Subsequently, a need may be invalidated as a result of further analysis. Generation dispatch, transmission flows, LMPs and surrounding loads will be among the items considered in finding the drivers for each need.

RELIABILITY NEEDS ASSESSMENT

PUBLIC POLICY NEEDS ASSESSMENT

The public policy needs assessment will be performed parallel to the reliability and economic needs assessments, and public policy needs of the system will be identified for each future and study year. Needs driven by public policy arise if the economic simulations identify conditions on the system that keep a utility from meeting its regulatory or statutory mandates and goals as defined by the renewable policy review and/or future specific public policy assumptions identified in the study scope.

PERSISTENT OPERATIONAL NEEDS ASSESSMENT

The needs identified by this criteria may be either economic or reliability related and will be included in the normal ITP detailed project proposal (DPP) needs list that is posted. The needs identified by this criteria will be evaluated using operational models that capture the actual occurrences. The applicable SPP stakeholder groups will approve these operational models to ensure consistency with the criteria established to designate the operational needs as persistent, rather than infrequent system needs. The evaluation criteria used to determine if these operational needs require projects are in a separate document. These candidate projects and associated justification will be presented to the TWG, ESWG and ORWG for their review.

- Economic
    - Flowgate Issues
        - Flowgates must reference monitored elements under the SPP tariff. Flowgates congested for at least 20 percent 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 24 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.
        - Congestion cost for outages will be provided for informational purposes.
    - Manual Commitments

        - Generation that is dispatched uneconomically in order to support voltage in the local area. Manual commitment events which include startup and extension 25 percent of the year will be added to the ITP needs list.
        - Manual commitments that do not exceed 25 percent of the year, but cost over $1 million dollars over 24 months will be added to the ITP needs list.
- Reliability
    - High/Low Voltage issues
        - Transmission operating guides that require reconfiguration and 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 percent of the time of the year due to non-outage issues. Transmission operating guides to be considered will only include transmission reconfiguration or potential load-shed events. Switched shunts and generator Mvar adjustments will be optimized prior to needs being identified.
            - If potential non-consequential load loss is 100 MW or greater, the risk to the load would need to be present 1 percent 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 elements, 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. If it has been implemented in real-time 25 percent of the time of the year, the issue will be added to the ITP needs list.
- Economic/Reliability
    - Operational Discretion
        - For issues that do not met the criteria described above, SPP Operations may propose additional needs. These additional needs will be identified with discretion for pain points observed in operating the transmission system and presented to ESWG and TWG for review and endorsement.

Project Acceleration:

- Projects identified by SPP Planning may be subject to accelerated need dates based on issues identified per the persistent operational issues criteria.

SHORT CIRCUIT NEEDS ASSESSMENT

SEAMS NEEDS

SOLUTION DEVELOPMENT AND EVALUATION

DETAILED PROJECT PROPOSAL (DPP) PROCESS

SOLUTIONS

Transmission Projects

Non-Transmission Solutions

Model Corrections

Operating Guides/Planning Guides

COST ESTIMATES

SOLUTION EVALUATION PROCESS

ECONOMIC SOLUTION EVALUATIONS

RELIABILITY SOLUTION EVALUATIONS

PUBLIC POLICY SOLUTION EVALUATIONS

Policy solutions will be evaluated based upon whether or not they resolve a public policy need. Projects that mitigate public policy needs will be included for further consideration during portfolio development.

PERSISTENT OPERATIONAL SOLUTION EVALUATIONS

INTERREGIONAL CONSIDERATIONS

PORTFOLIO DEVELOPMENT

PORTFOLIO DEVELOPMENT METHODOLOGIES

ECONOMIC PORTFOLIO DEVELOPMENT METHODOLOGY

RELIABILITY PORTFOLIO DEVELOPMENT METHODOLOGY

PUBLIC POLICY PORTFOLIO DEVELOPMENT METHODOLOGY

Once projects mitigating public policy needs are identified, they will be ranked by need based on their APC benefit in relation to their conceptual cost. Once study-level cost estimates are available, the ranking will be adjusted for that limited set of top-ranking solutions based on the updated cost. The highest-ranked project for each need will be selected for a grouping, then tested individually within the policy grouping to ensure there is no redundancy of need mitigation within the set of projects.

Commented [AG8]: Make sure this is defined

PERSISTENT OPERATIONAL PORTFOLIO DEVELOPMENT METHODOLOGY

PORTFOLIO SYNERGY

After the economic, reliability and policy portfolios are selected, checks for redundancy amongst the portfolios will be performed. The most economic set of projects within those portfolios meeting the same set of needs will be selected for further evaluation.

CONSOLIDATION

PROJECT STAGING

A project implementation plan will be developed for the final consolidated portfolio(s). The final portfolio(s) will be structured such that each element can be implemented in a staged manner as actual system developments approach the assumptions resulting in the need for that element. To help stage the projects SPP will utilize simulation results for years two, five and 10.

Each project classification will have its own methodology to determine a need date for upgrades to be included in the consolidated portfolio. Step changes between models, such as new generation or transmission upgrades in an area where an upgrade has been identified, may have an effect on the staging results for each method described below. In these instances, staff will consider these step changes to the model and the effect they have on the observed need-to-inform need date recommendations. Project staging will consider assumptions for the future(s) as determined in the study scope, current market conditions and other considerations.

Single Project Classification

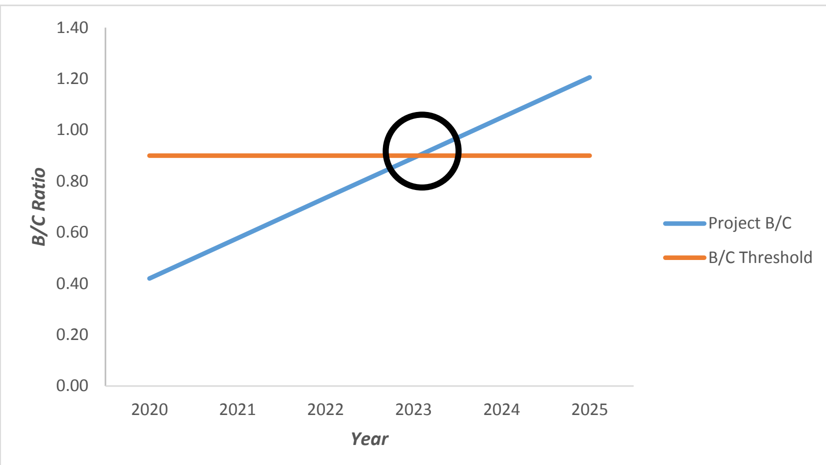
Staging for each type of project is described in the four sections below: economic projects, reliability projects, policy projects and persistent operational projects.

Multiple Project Classification

If a project is classified as more than solely economic, reliability, policy or operational, the project will be staged to meet the earliest need date established through the single project classification sections.

ECONOMIC PROJECTS

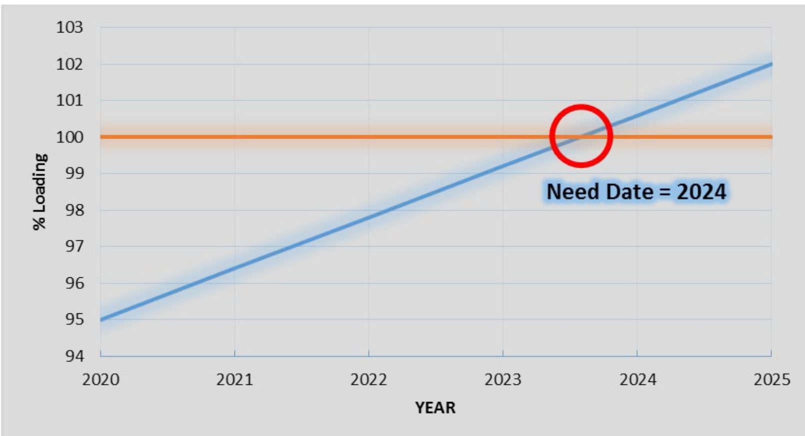
Economic projects in the final consolidated portfolio will be staged such that the B/C ratio of each upgrade exceeds 1.0. A linear interpolation of B/C ratios between each of the study years will be used to determine the need date. For example, an upgrade identified to address an economic need in year 10 will be staged between year five and year 10, based on linear interpolation of B/C ratios between the year five and year 10 models. The graph below represents the linear interpolation of B/C ratios of an upgrade. In this example, if year five is 2020 and year 10 is 2025, the need date would be determined to be 2023.



RELIABILITY PROJECTS

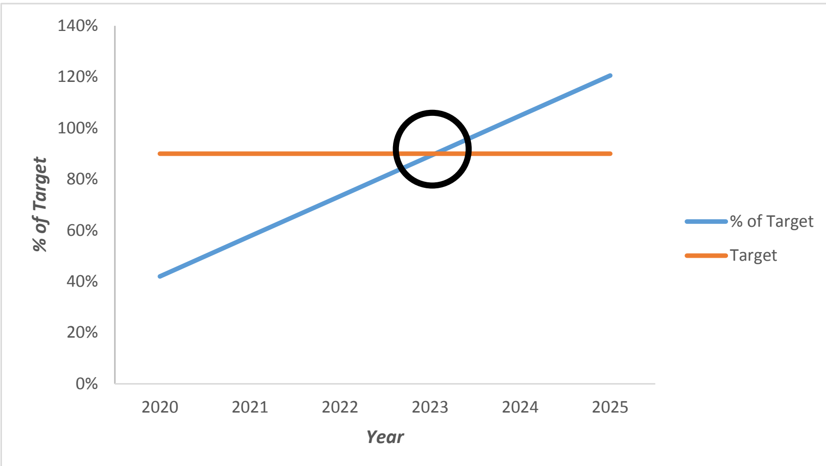
Reliability projects in the final consolidated portfolio will be staged based on the year when the needs addressed by each project appear on the transmission system. All upgrades which solve year two violations will be initially staged for an in-service date (ISD) in the corresponding season in which the violations occurs for year two.

For upgrades that solve observed reliability needs in year five and year 10, the reliability staging process will use a linear interpolation to evaluate thermal loading or the per-unit voltage value of the season in which the violation appears and the previous year/season model on record. For example, a violation that occurs in year five summer peak will be staged between year two and year five, based on the the results of linear interpolation between the year two summer peak and year five summer peak models. The graph below represents the linear interpoloation for thermal loading on a transmission line. In this example if year two is 2021 and year five is 2024, the need date would be determined to be June 1, 2024.



PUBLIC POLICY PROJECTS

Policy projects in the final consolidated portfolio will be staged according to when the public policy needs are resolved. A linear interpolation of the progress towards mitigating the public policy needs between each of the study years will be used to determine the staging date. For example, an upgrade identified to address public policy needs in year 10 will be staged between year five and year 10, based on linear interpolation of progress towards mitigating the public policy need between the year five and year 10 models. The graph below represents the linear interpolation of progress towards resolving the public policy needs. In this example, if year five is 2020 and year 10 is 2025, the need date would be determined to be 2023.



PERSISTENT OPERATIONAL PROJECTS

Projects deemed necessary to meet the reliability needs of the system due to persistent operational issues will have a need date the same as the issue date of the NTC.

Projects deemed necessary to meet the economic needs of the system due to persistent operational issues will be staged projects based on linear interpolation of B/C ratios from re-ran market studies with the upgrade.

FINAL ASSESSMENTS

BENEFIT METRICS

Benefit metrics will be used to measure the value and economic impacts of the final consolidated portfolio from the ITP planning process. Generally, a single portfolio will be tested in the approved future(s) by computing benefits and costs over a 40-year timeframe. For further detail on these metrics, refer to the Benefit Metrics Manual[15].

[15] https://www.spp.org/Documents/44031/20161108_Metrics_Manual_rev1.doc

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

SENSITIVITY ANALYSIS

Sensitivity analyses will be defined in the scope and conducted to measure the flexibility of the final portfolio in each ITP study. Generally, these sensitivities will not be used to select the proposed transmission projects, nor to filter out projects. The sensitivities to be performed on the final portfolio of each ITP study shall include, at a minimum:

1) High natural gas price
2) Low natural gas price
3) High demand
4) Low demand

Typically, for the demand sensitivities, one standard deviation on either side of the expected values will be used, and for the natural gas price sensitivities two standard deviations of expected values will be used.

FINAL RELIABILITY ASSESSMENT

STABILITY ASSESSMENT

DELIVERABLES

FINAL REPORT

PROJECT LIST

NTCS

ISSUANCE OF NTCS

STAFF AND STAKEHOLDER ACCOUNTABILITY

REVISION REQUEST PROCESS

A request to make additions, deletions, revisions, or clarifications to this ITP Manual shall be made in accordance with the Revision Request Process[16].

ACCOUNTABILITY PROCESS

APPENDICES

GLOSSARY

[16] SPP Revision Requests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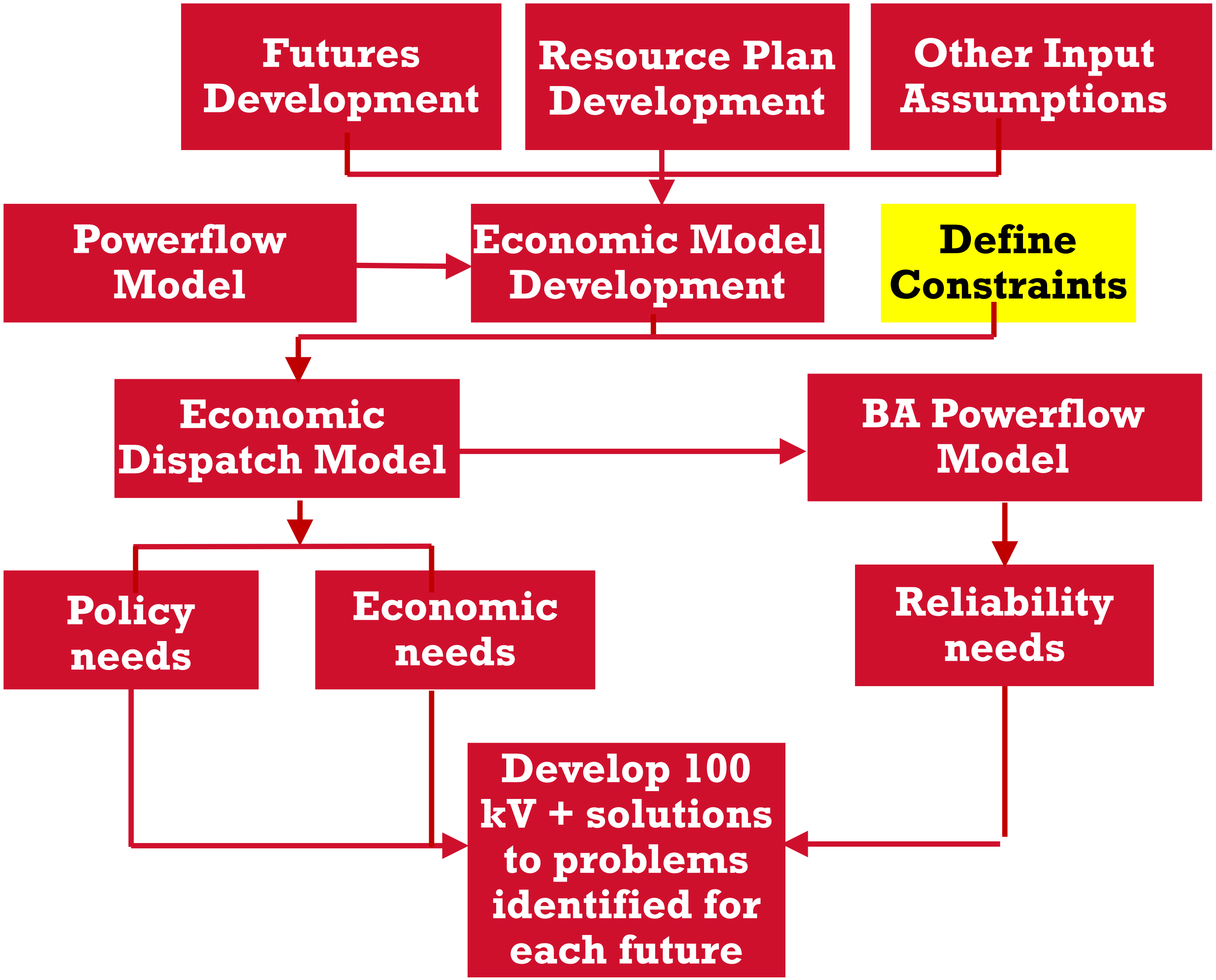
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.

Scope Standardization – Constraint Assessment

May 17, 2017

ITP10 Process



Discussion Topics

- TPL Planning Events (Approved) (Revised)
- Contingency Screening (Revised)
- Defining events (New)
- 69 kV Constraints (Approved) (Revised)
- Reclassification of Needs (Revised)

TPL Planning Events

- Current ITP Manual language

For the purposes of the ITP10 study, the transmission constraint list will be limited to the following types of issues so that there is a focus on disturbances on the HV and EHV systems:

- System Intact and N-1 situations
- Existing common right-of way and tower contingencies for 100+ kV facilities[7]
- Thermal loading and voltage stability interfaces
- Contingencies of 100 kV or higher voltage transmission lines only
- Contingencies of transformers with a 100 kV or higher voltage winding only
- Monitored facilities of 100 kV and above voltages only

Due to the limit on the number of constraints that can be monitored by the economic modeling tool, not every flow will always be mitigated for every hour. Overloads can occur. The constraint selection process is designed so that the constraints that would be most likely to occur during the simulated hours are mitigated.

[6] NERC Standard TPL-001-4 Table 1 includes outages of any two circuits of a multiple circuit tower as a Planning event P7, and the loss of all transmission lines on a common right-of-way as an Steady State & Stability Performance Extreme Event SS2.b.

[7] NERC Standard TPL-001-4 Table 1 includes outages of any two circuits on a common structure as a Planning event P7, and the loss of all transmission lines on a common Right-of-Way as a Steady State Performance Extreme Event SS2.b.

TPL Planning Events

Event Category	Voltage Level	Description
P0	EHV, HV	P0: No contingency
P1	EHV, HV	P1.1: Single (Generator)
	EHV, HV	P1.2: Single (Transmission Circuit)
	EHV, HV	P1.3: Single (Transformer)
	EHV, HV	P1.4: Single (Shunt)
	EHV, HV	P1.5: Single (Single Pole of a DC line)
P2	EHV, HV	P2.1: Single (No fault line section)
	EHV	P2.2: Single (Bus section Fault)
	EHV	P2.3: Single (Internal Breaker Fault [non-Bus-tie breaker])
P4 Multiple Contingency	EHV	Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section
P5 Multiple Contingency	EHV	Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following 1 Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section
P7 Multiple Contingency	EHV, HV	P7.1: Double (Transmission Circuit-Transmission Circuit on common tower

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TPL Planning Events

- Inconsistency between members on validity of certain Planning Events
  - Staff Action Item: Work with stakeholders to develop documented method on identification of Planning Events
  - Vetted through TWG for approval

- Staff Recommendation:
  - Staff recommends including **P1.2 and P1.3** events for contingencies; **P1.1**, P2, **P4, and P5** events for potential contingencies; and P7 events for contingencies if included in the list of permanent flowgates

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Contingency Screening Recommendation

- Staff recommends no changes:
  - Create outages for elements exceeding 50% loading for 100kV+ in Peak and Off-Peak hours
  - Create outages for elements exceeding 25% loading for 200kV+ in Peak and Off-Peak hours (SPP Only)
  - Continue copper plate analysis
  - Continue to include contingencies identified for SPP's Permanent and Temporary flowgates in all contingency lists

Defining Events

- Staff recommendation:
  - Create a constraint repository to use as a reference when reviewing constraint assessment results
  - Start with applicable portion of NERC book of flowgate
  - Perform 8760, Peak, and Off-Peak constraint assessment analyses utilizing screened contingency lists including monitored elements 100kV+
  - Analyze constraint assessment results to include most monitored elements with violations and use 8760 analysis violation hours and/or directional violation loading thresholds to limit number of contingencies (most severe) per monitored element
  - Strive for one event file to cover all years and futures with exception to topology differences and software limits on number events Peak and Off-Peak Constraints automatically included
  - Use economic model simulations as needed to limit number of events

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69 kV Constraints

- Current ITP10 process does not consider 69 kV limitations when performing SCUC/SCED process
  - Results in overloads for < 100kV facilities
- RC mostly considers Bulk Electric System
  - TOs request help for 69 kV system
  - 69 kV facilities are incorporated into the market by the use of temporary flowgates
  - ~25 Temporary FGs for 69 kV system currently
- Staff Recommendation:
  - Allow staff to use engineering judgement with feedback from SPP Operations to incorporate temporary flowgates on the 69 kV system into the constraint list **as well as 69 kV thermal violations observed in initial pass of SPP BA powerflow model**
    - Goal is to develop appropriate sized solution (69 kV for reliability or 100 kV+ for economic) for cause of violation
  - **May include stakeholder requested flowgates to properly control dispatch of resources on 69 kV system**

Reclassification of Needs

- Constraints can always slip through the cracks
- Sometimes end up as Reliability Needs
- Two examples from the 2017 ITP10
  - Upon identification, staff reconsidered constraints during the Side Bar analysis
  - Reclassified as economic needs
  - One constraints had economic potential, other did not
  - Final project recommendation considered economic evaluation
- Recommendation:
  - **Allow staff the ability to evaluate thermal violations observed in initial pass of SPP BA powerflow model, potentially add thermal violations as constraints for final pass. (DC/AC conversion feedback loop as input to final constraint assessment)**
  - Allow staff the ability to evaluate thermal violations observed in the Needs Assessment as potential constraints for reclassification or invalidation of the need as an economic issue. **(Reflect reclassification and invalidation in the needs posting to the extent possible.)**

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ITP Scope Standardization – Siting Process

May 17, 2017

Overview

- ESWG Action Item – SPP ITP Siting Process Whitepaper
- SPP staff draft – still in progress
  - Overall theme – Leverage existing ITP manual philosophies and 2017 ITP10 siting plan process with improvements from lessons learned
- Posted initial draft for stakeholder feedback (5/17)
- SPP staff is seeking feedback on structure and content by (5/24)
- Next steps
  - Finalize draft
  - Incorporate stakeholder feedback
  - Post draft for final review and approval
  - Approve whitepaper and recommendations for scope standardization
  - Draft language and approve language for standardized scope
  - Develop and implement recommended process

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Staff recommendations

- Document siting philosophy, rules, and exceptions
- Expand site repositories to include additional sites and site suitability attributes for stakeholder review and prioritization
- Leverage generation interconnection (GI) queue for all resource types
- Supplement GI queue as needed to maintain a balance with renewable potential across SPP
- Formalize staff and stakeholder responsibilities and roles
- Use available transfer capability to screen and prioritize sites in an effort to minimize generator outlet facility assumptions

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Siting Focus Today

- Conventional
  - What are allowable exceptions to siting conventional generation within the assigned owner's zone?
- Solar and Wind
  - When is it appropriate to consider sites with higher than average potential that have a lower GI queue position or no GI queue position at all?

Conventional Siting Concepts

- **ITP manual conventional generation siting philosophy** - Site proxy generation by region: Site expansion of conventional model generation in zone with highest capacity needs.
- **SPP Planning Criteria 4.4 Generation Planning 4.4.1 Design Futures** a) In order to maintain a balanced design of the electric system, excessive concentration of generating capacity in one unit, at one location, or in one area shall be avoided.
- Allowable exceptions to siting conventional generation in zone with highest capacity needs
  - Load pocket concerns
  - Fuel delivery concerns
  - Others on a case-by-case basis

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Solar and Wind Siting Concepts

- Leverage Generation Interconnection (GI) queue
- Maintain balance in renewable resource additions across SPP to minimize "chicken-and-egg" dilemma
  - As an example use remaining DOE/NREL technical solar and wind potential by state
  - Develop conceptual solar and wind sites as needed to supplement GI queue
  - Skip GI queue positions as needed
  - **Exclude Generator Outlet Facility assumptions as needed**
    - Allow study to evaluate regional economic and reliability benefits of generation and transmission alternatives as "additional analysis"

NREL wind capacity potential by State example

State	Potential Installed capacity[1] (MW)	SPP % of State	SPP Potential Installed Capacity (MW)	Current Installed Wind Power Capacity[2] (MW)	SPP Wind Siting Potential (MW)	State % of Potential
KS	884,359	100%	884,359	2,967	881,392	24.1%
NE	881,369	100%	881,369	812	880,557	24.1%
SD	844,019	70%	590,813	882	590,196	16.1%
TX	1,418,439	30%	425,532	15,635	420,841	11.5%
OK	390,592	100%	390,592	3,932	386,660	10.6%
ND	742,276	40%	296,910	1,886	296,156	8.1%
NM	340,116	30%	102,035	812	101,791	2.8%
MO	58,020	30%	17,406	459	17,268	0.5%
IA	464,787	10%	46,479	5,708	45,908	1.3%
MN	354,998	10%	35,500	3,035	35,196	1.0%
AR	2,126	30%	638	0	638	0.0%
MT	687,803	0%	0	665	0	0.0%
WY	422,713	0%	0	1,410	0	0.0%
LA	0	20%	0	0	0	0.0%

1. Potential installed capacity assuming land availability >= 35% GCF 80m hub height, circa 2008 turbine technology (http://apps2.eere.energy.gov/wind/windexchange/windmaps/resource_potential.asp)
2. As of 7/27/2015 (http://apps2.eere.energy.gov/wind/windexchange/wind_installed_capacity.asp)

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Utility-scale PV solar potential by State example

State	GW	GWh	Capacity Factor	%SPP	GW (SPP)	GWh (SPP)	%Potential By GW	%Potential By GWh
KS	6960	14500149	0.237826	100%	6960	14500149	20%	22%
TX	20411	38993582	0.218084	30%	6123.3	11698074.6	18%	18%
OK	4783	9341920	0.222962	100%	4783	9341920	14%	14%
ND	4870	9266757	0.217217	100%	4870	9266757	14%	14%
SD	5345	10008873	0.213763	70%	3741.5	7006211.1	11%	11%
NM	7087	16318543	0.262854	30%	2126.1	4895562.9	6%	7%
ND	5483	9734448	0.20267	40%	2193.2	3893779.2	6%	6%
MO	3157	5335269	0.19292	30%	947.1	1600580.7	3%	2%
AR	2747	4986389	0.207216	30%	824.1	1495916.7	2%	2%
MN	6510	10792814	0.189256	10%	651	1079281.4	2%	2%
LA	2394	4114605	0.1962	20%	478.8	822921	1%	1%
IA	4021	6994159	0.198563	10%	402.1	699415.9	1%	1%
WY	2854	5727224	0.229079	0%	0	0	0%	0%
MT	4403	8187341	0.212271	0%	0	0	0%	0%

http://www.nrel.gov/docs/fy12osti/51946.pdf

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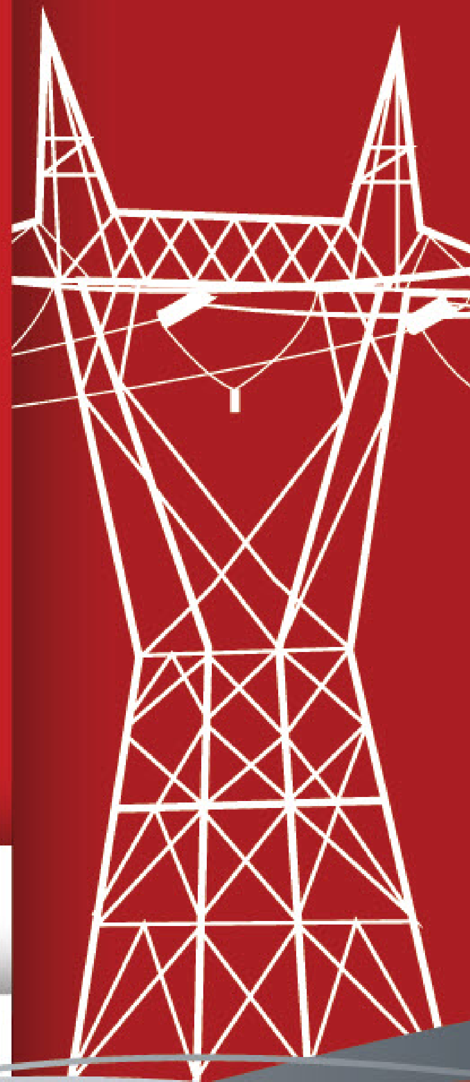
INTEGRATED TRANSMISSION PLAN SITING PROCESS WHITE PAPER (DRAFT)



SPP Southwest Power Pool

REVISION HISTORY

Date	Author	Change Description
05/17/2017	SPP Staff	Partial Draft for initial review

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

NO TABLE OF FIGURES ENTRIES FOUND.

SECTION 1: INTRODUCTION

1.1: Background and Purpose

SPP staff was requested by the Economic Studies Working Group (ESWG) to develop a more detailed procedure for conventional and wind generation planning and siting within the ITP process. This white paper focuses on improving, simplifying, and bringing consistency to the siting plan effort of the ITP process as well as documenting related topics, information, and alternative methodologies that can be expounded upon in the future.

1.2: White Paper Process

The underlying process used to develop this white paper involved documenting the current ITP siting objectives and practices, researching and collecting both internal and external information regarding the siting of future generation for both Regional Transmission Organization (RTO) and other planning purposes, soliciting stakeholder perspectives, and reflecting upon the lessons learned from the generation siting process implemented for the 2017 ITP10 study.

1.3: Siting process overview

The purpose of the ITP siting plan process is to determine and assign the most effective locations for prospective future generation to meet future resource needs. Siting of future generation is a cornerstone assumption in determining the transmission needs and transmission investment for the SPP region. The generation technology and siting assumptions can accelerate or defer the need for transmission investment. The siting process is preceded by a resource plan (RP) which quantifies resource needs for each predicted future. The resource plan is split into two phases:

1. Phase 1 (RP1) considers statutory/regulatory renewable mandates and goals for each state
2. Phase 2 (RP2) considers generation additions based on SPP staff recommendation and member approval as well as results from resource planning software

The resource planning milestone identifies deficiencies for conventional, wind, solar, biomass, and hydro generation. Future resources are added to the model to meet statutory/regulatory requirements and to meet reserve margin requirements to maintain a reasonable load-to-resource balance. Once the additional generation is determined, the generation must be modeled at a specific locations or sites in the study models.[1]

(Placeholder for High level description of Siting process)

Describe differences in assigning conventional prototypes compared to assigning solar and wind sites with varying capacity.

Step 1 – Screen and identify potential sites by zone by state by region

Step 2 - Prioritize sites by zone by state by region

Step 3 - Assign sites by zone by state by region

SECTION 2:SITING RESEARCH

2.1: Summary of other RTO Siting Processes (placeholder)

MISO Process[2]

- **Consideration of GI Queue resources (Planned, Future, and Canceled)**
- **Siting rules per future**
- **Site Priority**
    - **GI Queue resources**
    - **Brownfield Sites**

[1] Based on SPP staff and stakeholder concerns surrounding the 2017 ITP10 conventional generation resource plan results, SPP staff may amend this white paper to discuss options that might alleviate the concerns.

[2] https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=184861
MTEP14 Appendix E2 – EGEAS

        - **Retired/mothballed sites that have not been re-used**
        - **Greenfield sites using GI Queue**
        - **Greenfield sites using Greenfield siting methodology**
    - **Specific greenfield siting rules per resource type**
- **PJM Process[3]**
    - **Model Queued Generation by queue status**
- **ERCOT Process[4]**
    - **Resource Type Suitability by County**
    - **Use 345kV buses**
    - **Use highest LMP for competing sites**
    - **Siting Priority similar to MISO**

2.2: Summary of Utility Siting Process (placehoder)

2.3: Summary of NREL Siting Process (placehoder)

2.4: Summary of Stakeholder Meetings

SPP staff held one on one conferences calls with the liaisons and subject matter experts of a wide range of stakeholders.   The purpose of the meetings was to better understand differing perspectives regarding the generation siting process and to gain a better understanding of the more important criteria used to site new generation. The meetings were also used as a means to survey and build

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[3] https://www.pjm.com/documents/reports/rtep-documents.aspx

White Paper (PDF)7.2.2014

[4] http://www.ercot.com/content/committees/other/lts/keydocs/2013/DOE_LONG_TERM_STUDY_-_Draft_V_1_0.pdf

http://www.ercot.com/content/meetings/rpg/keydocs/2014/0722/LTSA_7-22-2014_Scenario_Results.ppt consensus on how SPP should generally approach siting for the purposes of transmission expansion studies and specifically for the 2017 ITP10 study.

1. Stakeholders reiterated the importance of conventional site suitability criteria to include access to adequate surface or groundwater supplies, access to adequate gas supplies without significant investment in gas delivery systems, and air permitting.

2. Stakeholders were in support of ranking brownfield sites over "greenfield" sites.

3. Stakeholders realize the necessity of SPP staff to rely on stakeholder feedback to determine the feasibility of potential sites and the reasonableness of siting plan results.

4. Stakeholders understand that the process is a screening level exercise and is not intended to replace a full scope power plant siting study.

5. Stakeholders were open to using GI queue for potential sites.

6. Stakeholders were concerned with solely leveraging the GI queue for renewables because the GI queue may not always represent renewable sites with the best capacity factors in SPP.

7. Stakeholders suggested solely siting at 345 kV buses.[5]

8. Stakeholders were open to using LMPs to inform siting along as there are no apparent market power concerns or cost recovery risks.

9. Stakeholders were open to remotely siting high potential solar from load centers which could result in more transmission expansion.

10. Stakeholders value cost-effective transmission expansion that increases access to high potential solar and wind resources and the associated production cost savings.

11. Stakeholders provided that state policy can encourage solar and wind to be sited more locally.

12. Stakeholders suggested developing siting philosophy and rules.

[5] This approach is used by ERCOT. SPP staff does support using 345 kV and 230 kV buses for conceptual renewable sites and "greenfield" conventional sites to limit resource plan impacts to 115 kV, 138 kV, and 161 kV transmission facilities and put more emphasis on 230 kV and above transmission facilities. Using this approach exclusively is not practical when compared to how existing generation is interconnected by voltage and might cause more 345kV and 230 kV transformation to 115 kV, 138 kV, and 161 kV limits to be unnecessarily identified as needs.

13. Stakeholders shared decision making techniques and tools.

SECTION 3: EVALUATION OF SITING PROCESS

3.1: SPP Siting Plan Process Gaps

The siting process to date has been a combination of using general guidelines within the ITP manual[6] and more specific siting criteria developed on a by study basis[7] with a key element being stakeholder input. The documented processes to date do provide general siting philosophies that give ample flexibility to perform the siting milestone of the ITP studies, but that flexibility necessitates a reworking of the process each planning cycle which can unnecessarily prolong the siting plan milestone. Also, a common theme has been once SPP staff has recommended a process and provided the results to stakeholders; the stakeholders make numerous adjustments which also prolongs the process. This can likely be attributed to not having more rigid siting rules and the permissible exceptions well documented, SPP staff having less "boots on the ground knowledge" compared to stakeholders, and/or a lack of a default standardized siting process that documents the protocols and roles of SPP staff and stakeholders with a set schedule detailing the exchange.

Prior to developing the siting process for the 2017 ITP10, SPP staff identified the following gaps in the siting process:

1. A need to leverage the existing SPP generation interconnection queue to identify potential sites, especially for wind resources, where it is understood that the generation interconnection queue answers questions regarding environmental obstacles, transmission capacity availability, and other barriers to development that would be difficult and time intensive for SPP staff to adequately answer.
2. A need to expand the suitability criteria to include a mechanism to identify whether adequate interconnection transmission exists for a potential site to help with prioritizing sites and minimizing generator outlet facility (GOF) assumptions that can introduce additional uncertainty to study assumptions.

[6]See Appendix 5.1: Existing ITP Manual language regarding resource plan and siting process

[7] See Appendix 5.2: 2013 ITP20 Generation Resource Expansion Siting Criteria

3. A need for a repository of conceptual sites by technology to track suitability attributes, prioritization, and stakeholder feedback from study to study.
4. A need to expand and formalize suitability criteria and prioritization rules to include permissible exceptions.
5. A need for load pocket analysis and criteria to recognize when capacity and energy based resources should be sited locally versus remotely in an effort to co-optimize generation and transmission expansion for load pocket efficiencies.
6. A need to expand the use of geographical information to perform more automated suitability analysis.
7. A need to leverage historic SPP Locational Marginal Prices experienced in the SPP Integrated Market place to help with prioritizing sites.
8. A need to be able to compare and track siting results to actual siting of generation as well as comparing siting result to a Network Customer's confidential resource plans.

3.2: 2017 ITP10 Siting Plan Improvements, Lessons Learned and Recommendations

SPP staff developed a siting plan for the 2017 ITP10 to address some of the observed gaps of the existing siting plan. What follows is a summary of the improvements, lessons learned, and additional recommended improvements that provide background to support the white paper recommendations.

Conventional Generation Siting Plan

Improvements

1. A siting repository was developed and provided to stakeholders for review early in the siting process that expedited the conventional siting process. The repository included sites from prior studies to take advantage of sites that had already been deemed to be reasonable by SPP staff and stakeholders. The repository allowed stakeholders and staff to suggest additional sites to be screened for available transmission interconnection capacity and to have discussions regarding suitability and site prioritization.

2. Available transmission capability was determined for each conventional site. The available transmission capability was used to prioritize sites and greatly reduced the amount of generator outlet facility assumptions made in the study.[8]

Lessons Learned and Recommended improvements

1. Proxy generation and generator outlet facility assumptions can unintentionally mask critical transmission needs and limits a study's ability to identify transmission solutions that may be more efficient.[9] SPP staff recommends following the general site rankings to be discussed later in this document for consistency unless staff and stakeholders perceive that proxy generation siting will significantly mask transmission needs or if stakeholders provide permissible exceptions to site rankings.[10] SPP staff recommends limiting generator outlet facility assumptions to the greatest extent possible. [11]
2. The newly established site repository only included information on planned retirements and available transmission interconnection capacity to rank conventional sites by zone. SPP staff recommends a more thorough build out of the conventional siting repository to include other suitability attributes and qualifications per site, and historic LMPs to help rank sites and build qualitative confidence in chosen sites.
3. The site repository did not consider all existing conventional generation sites, conventional generator interconnection (GI) queue sites, or a more comprehensive list of potential "greenfield" sites. SPP staff recommends that all existing conventional generation sites and any active or withdrawn GI queue sites be included in the repository for expansion considerations.

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[8]Generator Outlet Facilities assumptions have an unintended consequence of masking critical transmission needs and can introduce more uncertainty around assumptions and results.

[9]Transmission solutions may be less costly than generation additions as non-transmission solutions and provide more flexibility and efficiencies to load pockets.

[10]Exceptions may include load pocket concerns, site suitability concerns, or others on a case-by-case basis.

[11]An alternative Point of Interconnect for a site may be a preferred way to limit GOF assumptions over choosing a less desirable alternative site to limit GOF assumptions.

SPP staff recommends that a long term goal be to develop a more comprehensive list of "greenfield" sites using automated suitability analysis.[12]

4. A more efficient exchange of information needs to occur to improve the conventional siting plan. SPP staff recommends development of a flowchart and schedule to formalize SPP Staff and Member roles and responsibilities, including when, how, and what information[13] will be exchanged during conventional siting process.
5. Some directly impacted stakeholders did not proactively participate in the siting process. This primarily included some intra-zonal entities in zones with high capacity shortfalls. SPP staff recommends directly engaging entities who may be the primary driver of conventional resource plan additions to ensure that siting assumptions are reasonable.

Wind Generation Siting Plan

Improvements

1. The SPP generation interconnection queue was used to site wind to introduce more certainty around study assumptions than might be realized by a wind siting plan with less regard for the current GI queue.[14] The GI queue and study results inherently account for the "level of interest in development, the barriers to development, and the cost effective integration of the generation into the SPP region" that the ITP manual requires.[15] It also reduced the amount of effort required to determine GOFs, since those were already identified by the GI process.

Lessons learned and recommended improvements

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[12] One example to identify additional "greenfield" sites may include identifying where gas pipelines and transmission lines intersect each other.

[13] At a minimum, feedback about site potential and prioritization

[14] Using the GI queue was deemed appropriate for the 2017 ITP10 to best capture the immediate impact of wind farms likely to go into service far in advance of the 2025 study year. Unlike other resource types, the GI queue at the time of the 2017 ITP10 siting milestone included as much as 4 to 5GW of wind scheduled to proceed to commercial which was more than adequate for the amount of wind additions assumed for the 2017 ITP10 study.

[15] Obstacles being land use and land use restrictions, local incentives, and local opposition. Cost effective integration of generation is understood to be in areas of SPP that are projected to have lower congestion risks due to existing and planned transmission capacity t.

1. While it may be appropriate to solely use the GI queue for year 2, it may be less appropriate for year 5 and 10 of the new ITP study process given that there are drawbacks to solely using the GI queue. One of the major drawbacks of solely using the GI queue is that it may reintroduce the "chicken and egg dilemma" by underrepresenting areas of the system where the best renewable resources potentials exist.[16] SPP staff recommends solely using the GI queue for year 2 depending on available sites and using the GI queue for year 5 and year 10 supplemented by sites using an approximated wind potential value by sub-region, state, or GI study groupings to maintain a reasonable balance in a nondiscriminatory fashion between areas of the system with higher "potential development" and annual wind speeds compared to areas of the system with average "potential development" and annual wind speeds. This includes developing a repository of predetermined sites to help maintain this balance[17]. This may involve excluding any significant GOFs identified in prior GI studies that are the cause of the "chicken and egg dilemma" in order to allow the study to assess more efficient solutions that may have regional economic and reliability benefits.[18]
2. While the GI queue introduced more certainty in near term study assumptions, it is still difficult to gauge which queue positions with an "On-schedule" status are more likely to proceed than others. At the requests of stakeholders, SPP staff did send out a survey to TOs and GI customers with the purpose of further assessing the probability of resources going into service. This was leveraged to some extent for prioritizing the available wind sites from the GI queue. SPP staff recommends continuing with this survey as needed to help prioritize available solar and wind sites from the GI queue as well as leveraging internal information surrounding specific

[16] The transmission costs for these sites may be incrementally more but may be offset by the increase in annual production savings over areas of the system with average renewable potential.

[17] These predetermined wind sites for underrepresented areas of the system will consist of active and withdrawn GI queue positions, conceptual sites determined by NREL, staff or otherwise, and new interconnections that might be expected to occur in close proximity to approved EHV transmission facility additions not yet in service like the Chisholm View to Gracemont 345 kV line and the Gentleman to Thedford to Holt County 345 kV lines, preferably on 200 kV and above buses with high available interconnection capability. The sites will be modified as needed to account for generation interconnection activities at or near these sites.

[18] Any solutions developed where a GOF has been ignored may require additional analysis to assess regional economic and reliability before being recommended as a regionally funded Network Upgrade.

IA milestone and market registration progress that may indicate high likelihood of a project going into commercial operation.[19]

3. Determining where new or expanded wind farms might be developed is not a trivial problem. SPP staff recommends a long-range goal to improve the criteria for selecting GI queue positions based on historic interconnection milestone tracking and queue statistics and develop a more comprehensive list of conceptual sites using automated suitability analysis.[20]
4. (Insert) need to classify wind siting exceptions from 2017 ITP10

Utility – Scale Solar Generation Siting Plan

SPP staff performed extensive research and brainstorming with some trial and error to determine a reasonable approach to siting solar generation in the 2017 ITP10.

1. NREL's Solar Power Data for Integration Studies21 was used as the primary source of potential solar sites. The NREL data consists of synchronized hourly solar power forecasts for numerous distributed and utility scale photovoltaic (PV) plants for the year 2006 for each state. SPP staff developed a process to leverage the information that involved mapping the sites to SPP buses and ranking the sites by capacity factor and available transmission interconnection capacity.
2. NREL's Solar Global Horizontal Irradiation (GHI) map was used to define spatial and temporal sub-regions within SPP and restrict the mapping of the conceptual NREL solar sites to buses within those defined sub-regions. (Insert figure)
3. NREL's Technical Rural utility –scale PV Potential by state data was assessed to see what areas of SPP had the most potential. Insert figure

Lessons learned and recommended improvements

1. SPP staff originally envisioned a top-down approach to siting solar generation that would have resulted in siting more solar in the western portions of SPP than what was recommended for

[19] Careful consideration will be needed to protect any information that is deemed non-public and confidential.

[20] Similar to NREL processes and ITC white paper included as reference in Appendix X

[21] https://www.nrel.gov/grid/solar-integration-data.html

the 2017 ITP10.[22] SPP staff presumes that more utility scale solar will be developed in remote areas of the system with higher potential much like how wind has developed in SPP thus far.[23] SPP staff recommends prioritizing higher capacity sites in the southern and western portions of SPP to maintain a reasonable balance between areas of the system with higher capacity factors compared to areas of the system with lower than average capacity factors.

2. The GI queue and the 2006 NREL data set for solar was leveraged to create a list of potential sites for solar. For the 2017 ITP10 study, there was only a few solar requests in the GI queue that were active. There are now over 3 GW of active solar requests. SPP staff recommends using GI queue for solar in the same way recommended for wind.
3. A drawback of using the NREL's Solar Power Data for Integration Studies was the unintended consequences of inaccuracies introduced by the fact the dataset was not coherent with load and wind profiles being used for the 2017 ITP10 study[24]. SPP staff viewed this as a minor issue, considering there were no equivalent readily available alternative options with the same advantages.[25] SPP staff recommends continuing to use NREL's data set to supplement the GI queue with conceptual solar sites and for solar hourly profiles until a better alternative is available.
4. After further review of NREL's Solar dataset sites, SPP staff has observed that the longitude and latitude specified for each site represents a general location versus an exact location, and the location does not always account for amount of land needed for a site's MW capacity.[26] This observation would provide more flexibility in mapping sites to near-by buses than was allowed for the 2017 ITP10 process and reduce the unnecessary culling of sites with high capacity

[22] Some solar sites in the western portions of SPP were assigned to pricing zones in eastern portions of SPP where the resource need originated.

[23] Looking at currently active GI requests support this assumption.

[24] The solar dataset was derived using the 2006 weather conditions and the hourly load and wind shapes both being developed using alternative years where the weather conditions were not necessarily the same.

[25] The solar dataset was an independent dataset with spatial and temporal cohesion and considered as an indicative estimate of power production from future solar generation.

[26] There is no apparent geospatial information that distinguishes a site from its surroundings. As a rule of thumb, at least 10 acres/per MW of available land needs to be available for solar PV technology.
http://www.nrel.gov/docs/fy13osti/56290.pdf

factors.   SPP staff recommends NREL's conceptual sites be restricted to the highest ranked buses[27] within the sub-regions (insert figure reference) in SPP and that any NREL derived conceptual site and bus combination be screened for reasonableness by inspecting that adequate land without restrictions appears to be available.

5. Given that utility-scale solar development could occur almost anywhere in SPP, there is a greater chance of error between the selected conceptual sites and what actually gets developed. SPP staff presumes that the impact of the error on identifying cost-effective transmission expansion would be greater if the recommended process was to site more solar locally with lower capacity factors than site more solar remotely with higher capacity factors. Siting more solar locally than what might occur would likely reduce the ability of studies to identify west to east economic needs and cost-effective transmission solutions in a timely fashion. Siting more solar remotely than what might occur would increase the ability of studies to identify west to east economic needs and cost-effective transmission solutions that could otherwise be used to develop additional wind resources with high capacity factors.   SPP staff recommends adjusting the list of conceptual solar sites per study to closely align with the solar energy potential by state, irradiation maps, and GI queue outcomes.
6. (Placeholder) Describe minimum site capacity that is practical for each transmission interconnection voltage. Describe distribution interconnection assumption for sites with less than minimum site capacity on HV load buses
7. Determining where new or expanded utility scale solar farms might be developed is not a trivial problem. SPP staff recommends a long-range goal to improve the criteria selecting GI queue positions based on historic interconnection milestone tracking and queue statistics and developing a more comprehensive and prioritized list of conceptual sites using automated suitability analysis.[28]

Distributed Solar Generation Siting Plan (placeholder)

Biomass Generation Siting Plan (placeholder)

Demand –Side Resource Siting Plan (placeholder)

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[27] Buses with the highest available transmission capability and transmission or non-transmission interconnection feasibility.

[28] This might include trending and identifying the drivers behind changes in current land use activities. One unique example of this within the SPP footprint is how conservation efforts to sustain the Ogallala aquifer might drive changes from agricultural land use to solar land leases. https://www.nrcs.usda.gov/wps/portal/nrcs/detailfull/national/programs/initiatives/?cid=stelprdb1048809

Other lessons learned and recommended improvements

1. Available transfer capability was calculated for each resource type individually and overlap between different resource types was reviewed after choosing sites. SPP Staff recommends addressing any overlap in available transfer capability earlier in the process and adjust sites as needed to minimize GOF assumptions.

Conclusion

SPP staff recommends that site repositories, generation Interconnection queue, stakeholder involvement, available transfer capability, data from DOE/NREL, and minimizing GOFs continue to be key elements in the siting process. SPP staff recommends that the generation interconnection queue be supplemented with conceptual solar and wind sites as needed to maintain a balance with renewable potential across SPP using publically available technical potential estimates by state.

3.3: Conventional Siting Plan Philosophy Discussion and Recommended Changes (placeholder)

Discuss where this originates.

Provide commentary on each and recommended changes.

1. Do not use transmission as initial siting factor: Let geography and existing infrastructure guide placement of proxy generation. Existing transmission used as a weighting factor rather than a primary siting factor.
2. Site proxy generation by region: Site expansion of conventional model generation in zone with highest capacity needs.
3. Avoid greenfield siting for NG fired capacity: NG generation is flexible to site. Locating generally more peaking NG generation near load centers will have a tendency to reduce the impact on the transmission system.
4. Limit capacity to 2,400 MW maximum per location: Limiting total capacity per location potentially minimizes the impact of contingencies removing large blocks of capacity from service.
5. Site base load non-nuclear steam capacity in 600 MW increments; nuclear capacity in 1200 MW

SECTION 4:RECOMMENDED SITING PROCESS

4.1: Introduction (placeholder)

RP1 and RP2 will identify necessary resource additions, and generation will be sited in areas with appropriate potential. The sites will be developed utilizing those selected in previous studies, the GI queue, and sites provided by SPP staff and stakeholders using resource specific information. New generation will be sited if siting is not otherwise provided.

4.2: General Siting (placeholder)

4.3: Conventional Siting (placeholder)

Philosophy (placeholder)

Rules (placeholder)

Process (placeholder)

Site Repository (Placeholder)

Ranking Sites (Placeholder)

For siting base-load steam, coal, or integrated gasification combined cycle (IGCC) units, the following criteria should be considered. The site should be within one mile of two railroad lines with access to water needed for cooling purposes. It should be outside a 20-mile buffer of Federal Class I lands, a 25-mile buffer of air quality non-attainment regions, and a 25-mile buffer around major urban areas with populations greater than 50,000 and areas larger than 25 square miles. Additionally, locations will be prioritized based on locality to multiple railroad lines, coal mines, and gas pipelines.

For natural gas-fired combined-cycle generation criteria, the site should be located within ten miles of a gas pipeline, outside a 20-mile buffer for Federal Class I lands, and outside a 25-mile buffer of air quality non-attainment regions. Natural gas-fired combined-cycle sites are prioritized based on location relative to urban areas, railroads, navigable waterways, major rivers, and lakes.

Natural gas-fired simple-cycle generation criteria are that the site be within five miles of a gas pipeline, outside a 20-mile buffer for Federal Class I lands, and outside a 25-mile buffer of air quality non-attainment regions. Natural gas-fired simple-cycle sites are prioritized based on access to cross-overs of railroad line and gas pipelines, urban areas, railroads, and navigable waterways.

Due to the flexible nature of natural gas siting, in general, locating more peaking natural gas generation near load centers tends to reduce impacts on the transmission system.

When considering greenfield sites for conventional power generation, geographic information system (GIS) software will be used to identify legitimate locations. GIS software is a tool used to map SPP's footprint and other regions.

Results of the study will be posted for member review.

4.4: Wind Siting (placeholder)

Philosophy (placeholder)

Rules (placeholder)

Process (placeholder)

Site Repository (Placeholder)

Developing Conceptual Sites (Placeholder)

Ranking Sites (Placeholder)

Wind and solar resources will be added at a minimum percentage of load for that area. These minimums are most likely unique to the corresponding future. The amount of wind and solar needed by each area is determined according to future and year based on criteria for the current study.

The GI queue is used to create a list of potential wind sites which are then ranked according to their status. Listed below are the statuses, ranked from high to low:

- IA fully executed/commercial operation (placeholder)
- IA fully executed/commercial operation not fully on-line (placeholder)
- IA fully executed/on- schedule – The Generator Interconnection Agreement (GIA) is executed and the agreement milestones are being met.
- IA fully executed/on- suspension – The Generator Interconnection Agreement (GIA) is executed however the GI customer has requested that facility construction work be suspended.
- IA commercial operation not fully on-line – This is not an SPP GI Queue status. There are GI projects that are commercial operation with only a portion of the entire request installed. Subsequent phases of the project may have a later operational date.
- IA fully executed/Commercial Operation – The Generator Interconnection Agreement (GIA) is executed and the project has achieved commercial operation.
- IA pending – The facility study is completed for the Generator Interconnection (GI) request. SPP, the Interconnection Customer, and the Transmission Owner(s) are negotiating and drafting the Generator Interconnection Agreement (GIA).
- Facility Study Stage – The system impact study has completed for the Generator Interconnection (GI) request. The Transmission Owner(s) are further studying the required facilities.

- Definitive Interconnection System Impact Study (placeholder)
- Preliminary Interconnection System Impact Study (placeholder)

Sites are then ranked by capacity factor, the value of which is obtained from the National Renewable Energy Laboratory (NREL) prospector site.

Members will also be surveyed to gather information regarding prospective generation in the GI queue. Members will also assess the probability that a resource will go into service during the study's planning horizon. The responses aid in the prioritization of potential sites.

The needs outlined in RP1 are considered first because the requirements in RP1 are typically stricter. Once RP1's requirements are met, siting for needs of RP2 will begin.

In RP2, projects are ranked based on GI queue status, capacity factor, survey results, and transmission interconnection cost. Needs are then filtered by pricing zone. Sites chosen are pulled from the prioritized list and located in the state or states of operation whenever possible. However, attractive sites in other areas can and should be used before unattractive sites within the zone of operation. This matching of need to site is continued with the goal of spreading out the best sites. Developing diverse locations for sites reduces the potential number of contingencies created by clustering sites close to a load pocket. Preference is given to the owner of the location, staying within the state of operation when possible.

Additionally, if a company signs a contract to purchase a certain amount of wind in one year, that amount is unlikely to decrease in five years. If a site is a greenfield site and there is no wind generation currently at the site, maximum capacity is an important value. Greenfield sites will be avoided unless a large percent of the maximum capacity will be used.

Results of the study will be posted for member review.

4.5: Utility-Scale Solar PV Siting (Placeholder)

Philosophy (placeholder)

Rules (placeholder)

Process (placeholder)

Site Repository (Placeholder)

Developing Conceptual Sites (Placeholder)

Ranking Sites (Placeholder)

Solar sites are categorized as either utility-scale or rooftop solar. Utility-scale solar — such as solar farms — are large scale sites dedicated solely to generation of energy. Rooftop solar refers to areas that partially include the use of solar generation, such as residential areas. The GI queue and NREL are used to create a list of potential solar sites.

Utility-scale solar sites are first ranked by capacity factors in each pricing zone, then by kV and generator outlet capability. If pricing zones do not have enough NREL site capacity to meet that pricing zone's needs, solar will be sited in the pricing zone's state(s) of operation. NREL sites are only to be assigned to a single bus, not multiple.

The capacity factor for SPP as a region for each year in each future will be calculated. If any pricing zone's capacity factor is below the calculated average minus the standard deviation, solar assigned in that pricing zone will be assigned to another pricing zone with higher capacity factor sites.

Rooftop solar needs should be assigned per PROMOD demand group on a load ratio share methodology. The top 90th percentile load buses in each PROMOD demand group will be determined based on the approved powerflow model. Members provide feedback which will consist of a list of location for rooftop solar within their territories, or a list of industrial load locations to avoid.

The results of the siting for both utility-scale and rooftop solar will be posted for member review.

SECTION 5: APPENDICES

5.1: Existing ITP Manual language regarding resource plan and siting process

2.2.4 Resources
2.2.4.1 Conventional Resources
2.2.4.1.2 New Generation
The ESWG will develop a resource plan for each future scenario based upon expected unit retirements, unit derates, capital costs, O&M costs and other costs similar to those taken into account in data inputs for existing units, as well as other relevant factors as part of the development of a resource plan for each future. The Resource plan will be reviewed by the load serving entities for accuracy before modeling. Stakeholders have the opportunity to update their new generation data to ensure the resource plan is being implemented in a reasonable fashion. This data may include generator type and location of each new resource. The siting of Sensitivities may be employed in providing additional information to develop the final resource plan for each future scenario.
2.2.4.2 Renewable Resources
2.2.4.2.2 New Generation
Futures may require the modeling of additional wind and other renewable generation capacity above what is currently in service at the time of the assessment. The amount of renewable generation modeled is to be determined either as defined in futures identified in the scope, which is proposed by the ESWG and approved by the appropriate governing committee or through the analysis of the generation resource mix to be used in each future. The additional target renewable level is then met by including additional renewable generation sites in the modeling footprint. The size and locations of these additional renewable sites are approved by the ESWG. The ESWG will develop the locations of the renewable generation to be added taking into account the following factors: potential capacity factors as indicated by data from NREL; the SPP generation interconnection queue; known environmental obstacles to development; transmission capacity that exists in areas of SPP that are attractive for the location of renewable generation; the location of the need for the renewable generation; and other factors deemed relevant by the ESWG. The object of the generation added should take advantage of the best renewable resources within the SPP while taking into account the level of interest in development, the barriers to development, and the cost effective integration of the generation into the SPP region.
2.3 Model Development & Analysis
2.3.1.1 Resource Expansion Plans
For each future, SPP will complete forecasts of generating resource additions to balance load and capacity reserves for zones throughout SPP based on future scenarios designed by the ESWG. Siting locations for the new resources for each of the futures will be determined under the general guidelines of this manual. The resource additions will be added to the SPP database at the sited locations and interconnected in the transmission network model at the appropriate locations.
The resource planning will be conducted in three phases as summarized below.
☐**Phase I.** Develop a resource expansion plan for each future scenario. The resources will be selected using an optimal generation expansion model on a regional basis. The expansion plans will be developed from a resource list of generic prototype generators representing available future resources. The optimal generation expansion model will be constrained to maintain specified capacity margins, renewable requirements, and other parameters for each future.

☐**Phase II.** The new resources will be spatially located within the SPP sub-areas with the aid of GIS databases showing locations of transmission lines, natural gas pipelines, railroads, waterways, substations, as well as environmental maps and data indicating barriers to the location of generation; NREL studies on renewable energy potential; and data relevant to other factors that are to be used in the location of new resources pursuant to this manual.

☐**Phase III.** The generators will be entered into the SPP database and connected to busses in the transmission system.

2.3.1.1.1 Phase I

The data defining the generating characteristics of all existing and potential resources, demand and energy forecasts, fuel price forecasts, emission price forecasts, and other factors will be input to an optimal generation expansion model to evaluate combinations of candidate resources available to cost effectively meet future peak demand and energy requirements under the parameters of the applicable future scenario. This may include the addition of combinations of demand and supply resources as well as combinations of supply resources. Generators that are under construction or far enough along in the permitting process shall be considered for inclusion in the existing resource data. Firm retirements, to the extent known, will also be incorporated in the optimal generation expansion model.

Additionally, the parameters for each future will be entered into the optimal generation expansion model. The optimal generation expansion model will be used to determine the appropriate resources for the appropriate timeframe, maintaining the required minimum capacity margins, renewable requirements, and other parameters for each future.

Cost and performance estimates for representative generation technologies to be considered as generator resource additions will be entered into the optimal generation expansion model. An overall study estimate basis shall be developed to allow all technology costs to be presented on a consistent level. Technologies considered will include simple cycle combustion turbine configurations, combined cycle configurations, pulverized coal units, nuclear, integrated gasification combined cycle with carbon sequestration (IGCC), and renewable resources (wind, solar,…).

To capture the diversity of the geographic dispersion of wind generation in SPP's control region, hourly production profiles from several potential sites within the geographic regions that exhibit the best potential for wind installation development will be input to the optimal generation expansion model.

2.3.1.1.2 Phase II

After the sets of resources for each future are approved by the ESWG, the resources will be spatially sited. A physical spatial location for each generator will be selected based upon the siting parameters developed in collaboration with the ESWG and SPP staff. The resource sets will be provided to Transmission Owners for review. The siting effort will incorporate renewable needs, and other futures parameters, as well as physical siting criteria to determine the proper location for each resource. This siting effort will be conducted as a screening level exercise to identify site areas that generally comply with the approved criteria and will not be intended to provide or replace a full scope power plant siting study. Siting criteria could include, but not be limited to, locating the resources within a certain distance from existing natural gas pipelines, existing railways, and/or navigable waterways, etc.

The siting philosophy for conventional resources will incorporate the following general guidelines:

☐Do not use transmission as initial siting factor**:** Let geography and existing infrastructure guide placement of proxy generation. Existing transmission used as a weighting factor rather than a primary siting factor.

☐Site proxy generation by region: Site expansion of conventional model generation in zone with highest capacity needs.

☐Avoid greenfield siting for NG fired capacity: NG generation is flexible to site. Locating generally more peaking NG generation near load centers will have a tendency to reduce the impact on the transmission system.

☐Limit capacity to 2,400 MW maximum per location: Limiting total capacity per location potentially minimizes the impact of contingencies removing large blocks of capacity from service.

☐Site base load non-nuclear steam capacity in 600 MW increments; nuclear capacity in 1200 MW

2.3.1.1.3 Phase III

After the resource sites are approved, the new resources will be added to the SPP database and interconnected in the transmission network model at the appropriate locations. The data will be used in subsequent analyses by SPP and will allow SPP to connect the resources to specific buses for the transmission models.

5.2: 2013 ITP20 Generation Resource Expansion Siting Criteria

Southwest Power Pool, Inc.

2013 INTEGRATED TRANSMISSION PLANNING 20-YEAR ASSESSMENT

ESWG

Approved June 16, 2012

Generation Resource Expansion Siting Criteria

Purpose

A physical spatial location for each proxy generator will be selected based upon the siting parameters approved by the ESWG. Siting considered incorporation of the renewable requirements, and other futures parameters, as well as physical siting criteria to determine the proper location for each resource. Siting criteria included, for example, that the generator be located within a certain distance from an existing natural gas pipeline, an existing railway, and/or a navigable waterway.

This siting effort will be conducted as a screening level exercise to identify site areas that generally comply with the criteria approved by the ESWG, and is not intended to provide or replace a full scope power plant siting study. This document contains details on the siting process and sites selected for proxy locations of the generating resource associated with each Future.

Siting Criteria

At SPP's recommendation, siting of the generator resources forecast from the Strategist expansion model was based on the philosophy and rule-based methodology documented in the Joint Coordinated

System Plan ’08 report (JCSP)29. The JCSP’s siting philosophy and methodology is detailed in Section 5.2 of that report. In conjunction with stakeholder feedback and industry expertise the JCSP siting criteria was modified to met the needs of the ITP20 study. The siting guidelines are summarized in this subsection.

The general siting philosophy used by the JCSP and modified based on stakeholder feedback during the 2010 ITP20 is:

- **Do not use transmission as initial siting factor:** Let geography and existing infrastructure guide placement of proxy generation. Existing transmission used as a weighting factor rather than a primary siting factor.
- **Site proxy generation by zone:** Site expansion model generation in zone with highest capacity needs. In this study the zones are in general equivalent to SPP’s Balancing Authorities, although there are some deviations from direct correlations between the zones used in this study and the SPP Balancing.
- **Avoid greenfield siting for NG fired capacity:** NG generation is flexible to site. Locating generally more peaking NG generation near load centers will have tendency to reduce impact on transmission system.
- **Limit capacity to 2,400 MW maximum per location:** Limiting total capacity per location potentially minimizes impact of contingencies removing large blocks of capacity from service.
- **Consider energy prices in addition to capacity needs:** Energy prices may indicate opportunity for generation expansion.

When a zone contains merchant generation, it will be assumed that the merchant generation hosted by that zone will be available in the future to meet the load in that zone, even if it is not currently contracted to do so.

A priority based siting order was established to standardize locating generation as-needed and logical order:

- **Priority 1: Uncommitted locations within generation interconnection queues.**
- **Priority 2: Brownfield sites.** Not all brownfield sites are ideal for new capacity so stakeholder feedback will be solicited to identify sites that are good candidates and sites that are not good candidates.
- **Priority 3: Retired/Mothballed sites which have not been reused.** Transmission and other infrastructure may still exist at the site and could be recommissioned with new capacity.

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[29] "Joint Coordinated System Plan 2008 (JCSP’08)." Available at: https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=16485 https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=16486

- **Priority 4: Greenfield sites – Cancelled or postponed projects.** Sites proposed through interconnection queues and cancelled may be good candidates. Known reasons why a project was cancelled, to determine the sites viability for inclusion/exclusion for consideration as a candidate site were solicited from stakeholders and SPP staff.
- **Priority 5: Greenfield sites.** Sites with no existing or planned development.

Greenfield Siting Details

The lowest priority sites considered for siting the expansion plan generators focuses on pure greenfield sites. To identify legitimate locations for new generation sites, a rule set was adapted. GIS software will be used to help facilitate indentifying legitimate locations. Criteria were developed based on generator technology. The following criteria were used to consider a greenfield location for siting Base load Steam Coal or IGCC:

- Within one mile of two railroad lines
- Has access to needed water for cooling
- Outside a 20 mile buffer of Federal Class I lands
- Outside a 25 mile buffer of an air quality non attainment region
- Outside a 25 mile buffer surrounding a major urban area (a population greater than 50,000 and an area larger than 25 sq. miles[30])

To differentiate between multiple locations that meet the base load steam coal and IGCC siting criteria, locations were prioritized based on locality to multiple railroad lines, coal mines, and gas pipelines.

Criteria for siting natural gas fired combined cycle generator technologies are:

- Within ten miles of a gas pipeline
- Outside a 20 mile buffer of Federal Class I lands
- Outside a 25 mile buffer of an air quality non attainment region

Natural gas fired combined cycle sites prioritized based on location relative to urban areas, railroads, navigable waterways, major rivers, and lakes.

Natural gas fired simple cycle generator technologies siting criteria are:

- Within five miles of a gas pipeline
- Outside a 20 mile buffer of Federal Class I lands

[30] This is consistent with the Geographic Areas Reference Manual published by the U.S. Census Burea; http://www.census.gov/geo/www/garm.html; June, 2012

- Outside a 25 mile buffer of an air quality non attainment region

Natural gas fired simple cycle sites prioritized based on access to cross-overs of railroad line and gas pipelines, urban areas, railroads, and navigable waterways.

The expansion planning model did not forecast any new nuclear units in the SPP footprint by 2030. An initial siting criterion for nuclear units was to site them at brownfield locations with existing nuclear generation.

Wind Siting

Two categories of wind resources will be sited:

1) those existing and in-service by the end of 2013 as identified in the 2012 Policy Survey and
2) generic wind sites that will meet any remaining wind energy mandates, goals, or exports not satisfied by the existing and in-service wind sites.

Wind resources that are in service or under construction will be explicitly sited in their corresponding locations. Generic sites will be sited at EHV substations based on the locations selected in the 2012 ITP20 and 2010 ITP10. Stakeholder input will be sought in order to adjust the location of these sites as needed.

5.3: References (placeholder)

http://www.nrel.gov/gis/re_potential.html

http://www.nrel.gov/gis/re_econ_potential.html

http://www.nrel.gov/gis/images/80m_wind/USwind300dpe4-11.jpg

https://www.nrel.gov/grid/renewable-resource-data.html

http://www.nrel.gov/docs/fy13osti/56290.pdf

http://www.nrel.gov/docs/fy12osti/51946.pdf

http://www.nrel.gov/docs/fy10osti/47434.pdf

http://apps2.eere.energy.gov/wind/windexchange/windmaps/resource_potential.asp

https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2016/MTEP17%20Futures%20Development%20Workshops/20160428/20160428%20MTEP17%20Futures%20Development%20Workshop%20Presentation.pdf

https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2016/20160615/20160615%20PAC%20Item%2002bii%20PAC%20Siting%20Update.pdf https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2016/20160316/20160316%20PAC%20Item%2002c%20MTEP%2017%20Futures%20Kickoff%20Siting%20Process%20Review.pdf

https://www.spp.org/documents/22887/itp%20manual.pdf

https://content.ces.ncsu.edu/threshold-issues-for-landowner-solar-leasing

https://www.nrcs.usda.gov/wps/portal/nrcs/detailfull/national/programs/initiatives/?cid=stelprdb1048809

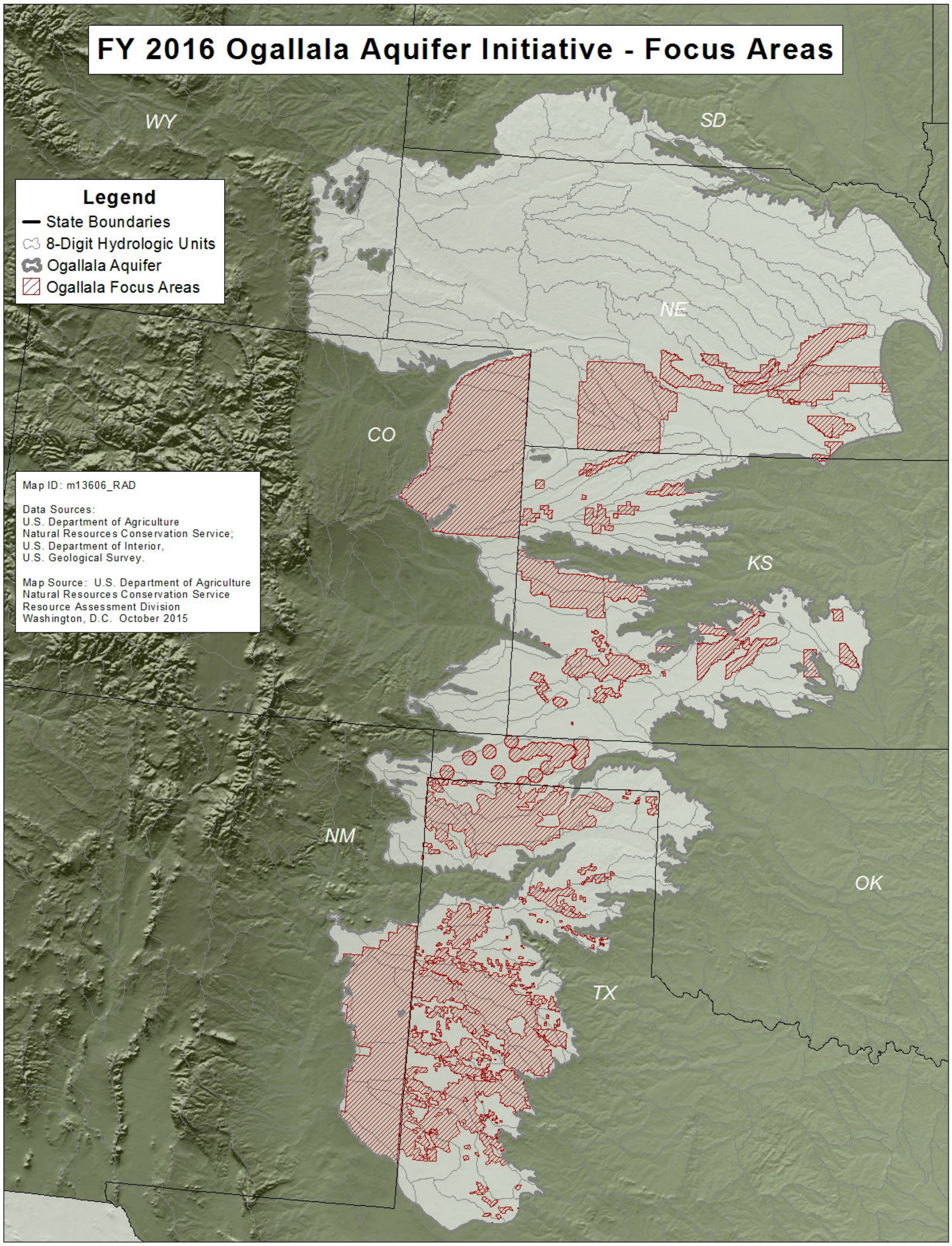

Figure 1.1 FY 2016 Ogallala Aquifer Initiative - Focus Areas

5.4: General Site Suitability Criteria by Generation Type (placeholder)

Insert ITC wind siting white paper and presentation

5.5: List of load pockets by study (placeholder)

2012 ITP10

2017 Variable Integration Study

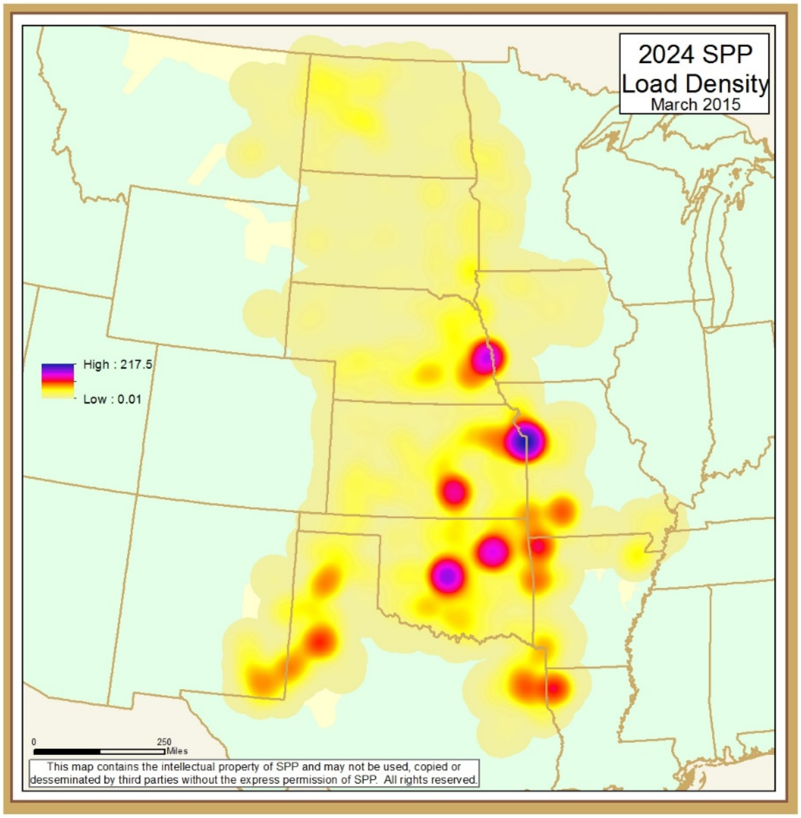

Figure 1.2 2024 SPP Load Density Map

5.6: Definitions (placeholder)

5.7: Related Topics, Information, and Alternative Siting Methodologies not covered by this white paper (placeholder)

Market Power Analysis

Loss of Load Expectation Analysis

Alternative renewable generation siting processes

Benefits of siting renewables in remote areas with highest resource potential