INTEGRATED TRANSMISSION PLANNING MANUAL

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By SPP staff

Version 2.17A

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
1.0	SPP Staff	Initial Draft approved by the MOPC.	
1.1	SPP Staff	Incorporated TWG and ESWG edits to the ITPNT and ITP20 sections.	
1.2	SPP Staff	Revised Draft approved by the MOPC.	
1.3	ESWG	Accepted Task Force Edits	
2.0	SPP Staff	Implementation of TPITF recommendations	New ITP process utilized for 2019 ITP
2.1	SPP Staff	Incorporate RR276, renewable VOM Pricing	
2.2	SPP Staff	Incorporate RR 314: ITP Manual Model Build Updates	
2.3	SPP Staff	Incorporate RR 321: Clean up Items	MOPC Approval 10/16/2018
2.4	SPP Staff	Incorporate RR 362: Renewable Curtailment Pricing	MOPC Approval 7/19/2019
2.5	SPP Staff	Incorporate RR 368: Section 4.2.6 Clarification (Local Planning Criteria) Incorporate RR 384: Section 2.1.1 Base Reliability Generator Retirement Modeling	MOPC Approval 10/15/2019
2.6	SPP Staff	Incorporate RR388: Sections 2.2.1.6.2 and 2.3.1.1 - Resource Plan and PST Modeling Incorporate RR392: Sections 2.1, 2.1.1, 2.1.1.1, 2.1.4, 10.3 - Modeling and Process Waiver Updates Incorporate RR395: Section 2.2.1.7 - Natural Gas Price Forecast Methodology Incorporate RR396: Section 7.2 - Sensitivity Scoping During Futures Development	MOPC Approval 01/15/2020
2.7	SPP Staff	Incorporate RR367: Load Forecasts for Resource Planning purposes	MOPC Approval 10/15/2019

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
		Incorporate RR379: ITP Market Powerflow Peak Hour Selection	
2.8	SPP Staff	Incorporate RR403: Change to ITP Operational Model Development	
2.9	SPP Staff	Incorporate RR448: Removing RPS Table from ITP Manual and placing in Scope	MOPC Approval 4/13/2021
2.10	SPP Staff	Incorporate RR450: Section 5.1.1.4 & 5.1.1.4.1: Establish operating guides in ITP Manual Incorporate RR478: Section 2.2.2.1.2: Conventional Resource Expansion Plan Note: RR 476 approved at MOPC, but is pending FERC approval of tariff changes before those changes will be applied to ITP Manual.	MOPC Approval 1/10/2022
2.11	SPP Staff	Incorporate RR482: Section 2.2.1.4: Resource addition request approvals Incorporate RR485: Section 2.2.1.10: Renewable pricing	MOPC Approval 4/11/2022
2.12	SPP Staff	Incorporate RR489: Section 2.1.1: Generation Resources & Section 2.1.2: Long-Term Firm Transmission Service	MOPC Approval 7/11/2022
2.12	SPP Staff	Incorporate RR498: Section 2.2.1.4: SPP Resource Addition Requests Incorporate RR500: Section 2: Model Development & Section 10.3: Data Submission Update	MOPC Approval 10/11/2022
2.12-A	SPP Staff	**RRs waiting on FERC approval of tariff language:** Incorporate RR452: Section 4.2.6 & Section 5.3.5: Transmission Owner Evaluation Process Incorporate RR476: Section 5.1.1.2, Section 5.1.1.3 & Section 5.3.2: SATOA	MOPC Approval 7/11/2022 & 10/11/2022

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
2.13	SPP Staff	Incorporate RR452: Section 4.2.6 & Section 5.3.5: Transmission Owner Evaluation Process	FERC Approved Language 5/26/2023. Effective immediately
2.13A	SPP Staff	**RR is waiting on FERC to grant an effective date.** Incorporate RR476: Section 5.1.1.2, Section 5.1.1.3 & Section 5.3.2: SATOA	FERC has approved language as of 5/26/2023; however, no effective date has been granted by FERC, so this language is still pending.
2.14	SPP Staff	Incorporate RR552: Section 2.1.1: ITP Base Reliability Resource Inclusion	MOPC Approval 07/10/2023
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2.16A	SPP Staff	**RR is waiting on FERC to grant an effective date.** Incorporate RR476: Section 5.1.1.2, Section 5.1.1.3 & Section 5.3.2: SATOA	FERC has approved language as of 5/26/2023; however, no effective date has been granted by FERC, so this language is still pending.

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
2.17	SPP Staff	Incorporate RR645: Section 6.1 and RR646: Section 2.2.3.1	MOPC Approval 10/15/2024
2.17A	SPP Staff	**RR is waiting on FERC to grant an effective date:** Incorporate RR476: Section 5.1.1.2, Section 5.1.1.3 & Section 5.3.2: SATOA. **RR is waiting on FERC to approve Tariff language:** Incorporate RR649: Section 2.1.1.1	FERC has approved language for RR476 as of 5/26/2023; however, no effective date has been granted by FERC, so this language is still pending. MOPC approval for RR649 10/15/2024

CONTENTS

1 INTRODUCTION

1.1 PURPOSE

The SPP Open Access Transmission Tariff (OATT or SPP tariff) Attachment O requires Southwest Power Pool, Inc. (SPP) to conduct the Integrated Transmission Planning (ITP) Assessment in accordance with this Integrated Transmission Planning Manual. This manual will outline the methodology, criteria, assumptions, and data necessary for the ITP assessment.

The ITP assessment is a regional planning process built to leverage knowledge of the transmission system's reliability, public policy, operational, and economic needs, as well as compliance, generator interconnection, and transmission service request impacts to develop a cost-effective transmission portfolio over a 10-year planning horizon. A common set of foundational modeling assumptions will be utilized as the starting point for all planning studies. System needs resulting from generator 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 ITP assessment to facilitate continuity in the overall transmission expansion plan. This targeted approach is both forward-looking and proactive, designed to facilitate a cost-effective and responsive transmission network that adheres to the ITP principles (listed in History of the ITP Assessment), while following the Federal Energy Regulatory Commission (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, operational, and economic considerations in project or portfolio recommendations. The assessment of a project or group of projects' performance may include:

- Performance across multiple futures
- Ability to solve multiple need types
- Reliability impacts related to compliance with North American Electric Reliability Council (NERC) Standard TPL-001[2]
- Operational impacts

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

This manual includes standardized language detailing ITP assessment items that were reviewed by the appropriate SPP stakeholder groups and approved by the Markets and Operations Policy Committee (MOPC). This standardization will provide specific details on each scope item and eliminate the need for repetitive reviews and approvals to help facilitate the performance of a planning cycle that produces an annual report. An ITP assessment scope will be developed for each

[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.

[2] NERC TPL-001

ITP assessment for items that will require SPP stakeholder review and approval with each new study. This process is described further in the Study Scope Document section of this manual.

1.2 REVISION REQUEST PROCESS

A request to make additions, deletions, revisions, or clarifications to this ITP Manual shall be made in accordance with the SPP revision request process.[3]

1.3 OVERVIEW OF THE SPP ITP ASSESSMENT

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

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

1.3.1 ORGANIZATIONAL GROUP SUPPORT

The Economic Studies Working Group (ESWG) identifies and maintains the economic data, data sources, models, economic planning methodology and processes, and benefit metrics to be used in the evaluation of economic expansion needs in the SPP region.

The Transmission Working Group (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 identifying needs associated with persistent operational issues.

The ITP recommended plan will be reviewed and may be endorsed by ESWG, TWG and MOPC.

1.4 WORKING GROUP OWNERSHIP

ECONOMIC STUDIES WORKING GROUP

Generally, the ESWG will be responsible for review of data and results for the following items:

[3] SPP Revision Requests

- Scope
- Scenarios development
- Load forecasts
- Existing and planned generation
- Renewable policy requirements
- Resource plan
- Market Economic model
- Economic analysis
- Recommended plan
- Benefit metrics
- Sensitivities
- Assessment report

TRANSMISSION WORKING GROUP

Generally, the TWG will be responsible for review of the data and results for the following items:

- Scope
- Transmission topology
- Load forecasts
- Existing and planned generation
- Base reliability models
- Market Powerflow models
- Constraint assessment
- Reliability analysis
- Recommended plan
- Assessment report

MODEL DEVELOPMENT WORKING GROUP

Generally, the MDWG will be responsible for review of the data for the following item:

- Load forecasts
- Existing and planned generation
- Transmission topology

SEAMS STEERING COMMITTEE

The Seams Steering Committee (SSC) will be responsible for the review of the following:

- Seams impacts

STRATEGIC PLANNING COMMITTEE

The Strategic Planning Committee (SPC) will provide input for the following items:

- Scenarios development
- Policy decisions

MARKETS AND OPERATIONS POLICY COMMITTEE

MOPC will make a recommendation to the SPP Board regarding approval decisions of the following items:

- Assessment report

REGIONAL STATE COMMITTEE

The RSC will review the following items:

- Assessment report

SPP BOARD OF DIRECTORS

The Board will make approval decisions for the following items:

- Assessment report
- Recommended plan

1.5 ITP ASSESSMENT SCHEDULE

The planning cycle, as illustrated in Figure 1, will consist of scope development and model development for approximately 12 months and a planning assessment period of approximately 12 months. The scope and model development for the succeeding cycle will begin concurrently with the planning assessment period of the preceding study resulting in a 12-month overlap. This planning cycle will result in an annual assessment report with a set of recommended projects.

The assessment will also satisfy the NERC Standard TPL-001 short-circuit and portions of the NERC Standard TPL-001 steady-state assessment requirements. The ITP assessment will assess years 2, 5, and 10 for reliability, public policy, operational, and economic needs.

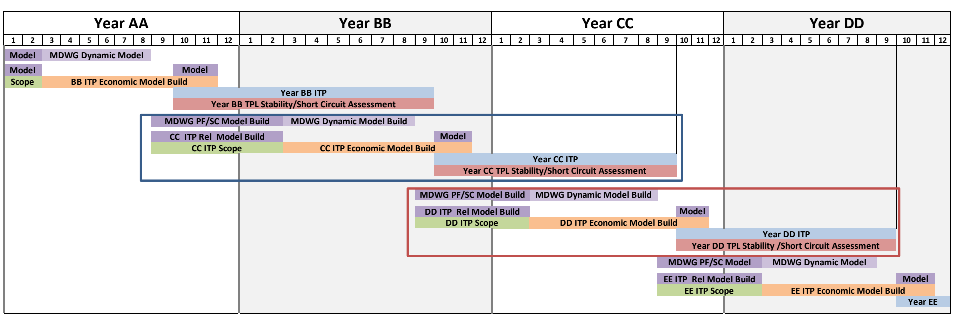

Figure 1: ITP Cycle

1.6 STUDY SCOPE DOCUMENT

To provide 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 SPP 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.

1.7 CONSIDERATION OF NERC STANDARD TPL-001

The analyses performed for the holistic planning assessment described in this manual allow SPP to meet the requirements of the SPP tariff, as well as a portion of the NERC standards for transmission planning requirements detailed in NERC Standard TPL-001. This allows for a consistent approach in the planning processes while allowing SPP to issue NTCs to transmission owners (TOs) to construct upgrades needed to meet certain NERC Standard TPL-001 Table 1 requirements.

The Reliability Needs Assessment section detailed in this manual will describe the assessment of transmission system planning events in NERC Standard TPL-001 Table 1 for which non-consequential load loss or the interruption of firm transmission service is not allowed. A common powerflow analysis for the ITP assessment and NERC Standard TPL-001 will be performed for these planning events. Additionally, the short-circuit analysis required by NERC Standard TPL-001 will be performed and a subset of those needs will be considered as ITP needs.

While these analyses will be common to both the ITP assessment and the requirements of the NERC Standard TPL-001, SPP will continue to compile and issue a separate annual report (SPP Compliance Assessment) to fully document SPP's compliance with all NERC Standard TPL-001 requirements.

2 MODEL DEVELOPMENT

Table 1 lists the model sets for the ITP assessment cycle. After the model sets are finalized for the ITP assessment, no model changes will be accepted to update the model. Any identified model changes after the models are finalized will be required to be submitted during the detailed project proposal (DPP) window as detailed in section 5.1.1.3.

Description	Year 2	Year 5	Year 10	Total
Base Reliability	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
Market Economic Model	One Future (1)	Each Future (1-3)	Each Future (1-3)	3-7
Market Powerflow Model	One Future's Peak and Off-Peak (2)	Each Futures' Peak and Off-Peak (2-6)	Each Futures' Peak and Off-Peak (2-6)	6-14

Table 1: ITP Model Sets

2.1 BASE RELIABILITY MODEL OVERVIEW

The base reliability model set will be the base model set for all of SPP's planning processes including transmission service, generator interconnection, and compliance studies. 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 will consist of non-coincident peak load forecasts, assumed long-term firm transmission service usage levels, and expected conventional and renewable resource output levels.

Model data related to the NERC MOD-032 standard, should be in accordance with the SPP MDAG Model Development Procedure Manual. Information needed to develop the models will be provided by SPP TOs and stakeholders with appropriate review opportunities by SPP and stakeholders, prior to receiving final approval. These inputs, described in the following sections, include but are not limited to:

- Generation resources
- Load forecasts
- Definition of the SPP footprint
- Topology
- Modeling of firm transmission service
- DC tie modeling
- DC line modeling
- Phase-shifting transformers (PSTs)
- NTC re-evaluation requests

A short-circuit model will be developed for a short-circuit assessment in consideration of NERC Standard TPL-001.

2.1.1 GENERATION RESOURCES

Resource Inclusion and Availability

Generation resources[4] shall be included in the base reliability model if any of the following requirements are met:

1. The generation resource is existing and in service.
2. The planned generation resource has an effective Generator Interconnection Agreement (GIA), not on suspension.
3. The planned generation resource is approved by the TWG as meeting the requirements detailed in the Generation Resource Waiver Requests section of this manual.
4. The planned generation resource has been identified by SPP as necessary[5] to solve a model and is approved for inclusion by the TWG[6] with considerations such as:
    a. Resources in the generator interconnection queue.
    b. Resources have been included in an approved SPP-developed resource plan.

Resource Dispatch

Generation resources will be available for dispatch in the base reliability model if either of the following criteria are met:

1. The resource has approved long-term transmission service with an effective transmission service agreement, or
2. SPP has identified the resource as necessary to solve a model.

If a generation resource is utilized solely for reactive support, it will be dispatched to its P_{min} value in the appropriate model(s). TWG approval will include the specific models for which the generation resource, reactive resource, or transmission upgrade will be included.

Dispatch will not surpass the lesser of gross P_{max} or net designated resource amount plus the station service load. Additionally, the total dispatch of resources that share a POI will be limited to the total GIA(s) Interconnection Service amount(s) granted at the POI adjusted for the total station service load.

Generation resources that have been mothballed or are planned for retirement must be submitted to SPP through SPP's MOD Application and the SPP RMS for the base reliability model. Upon receiving this information, if the resource is still listed in the applicable Service Agreement, the resource may be dispatched to address shortfall. If planned retired generation resources are identified for dispatch, SPP will notify the modeling entity to coordinate the dispatch for the affected parties.

[4] Associated transmission upgrades will be modeled in accordance with the SPP tariff
[5] Reactive resources or previously approved transmission upgrades will also be considered as potential solutions.
[6] Resources added for this criteria will not be included in the Market Economic model and Market Powerflow unless they are also identified in the resource planning process

Resources considered required to be online may be modified in order to displace renewable generation in the planning models. These resource types include, but are not limited to: area slack machines, hydroelectric, cogen, landfill gas, and nuclear.

Shortfall Process[7]
Shortfall occurs when an entity does not have enough dispatchable generation to serve the entity's load. When a shortfall scenario appears in the models, the following actions will be taking in this order until the load is served:

1. Exhaust the dispatchable generation of the network customer.
2. Exhaust the independent power producers (IPP) dispatchable generation in the same model area.
3. Dispatch the remaining unused, dispatchable generation on a pro rata basis within SPP footprint.
4. When all other options have been exhausted, including the waiver process, include generation resources[8] from the most recently approved ITP resource plan.

2.1.1.1 Generation Resource Waiver Requests

Certain generation resources and associated transmission service requests that have not fully completed the processes defined in Attachment V and either Z1 or Section 30.2.2 of the SPP tariff but have a high probability of going into service or obtaining an effective transmission service agreement can be included in the base reliability model. Generation resources that meet all of the following requirements will be included:

1. A formal request has been sent to SPP requesting the generation resource be included in the base reliability model.
2. The generation resource has an effective interim GIA.
3. The generation resource has entered the aggregate transmission service study or equivalent transmission service evaluation process publicly posted on OASIS and, if required for transmission service, has a completed facilities study that is awaiting final results without unmitigated third-party impacts.
4. The generation resource has acquired air and environmental permits where applicable.
5. The generation resource has started construction with major equipment funding and procurement contracts awarded.

Commented [SP1]: RR649 has language pending - drafting filing for FERC

If a generation resource does not meet all of the above requirements, a formal request for resource inclusion in the base reliability model can be submitted to the TWG for approval. The TWG will take the following information into account in deciding whether to approve the waiver:

1. A formal request has been sent to SPP requesting the generation resource be included in the base reliability model, including any additional information deemed relevant by the requesting entity. The request should identify which transmission upgrades will be deferred, if applicable.
2. The generation resource has a mitigation plan for the deferred transmission upgrades until it makes a financial commitment to complete the required upgrades.

[7] Renewable generation or other generation with operating restrictions shall not be used.
[8] Study needs generated by the addition of these generation resources will not automatically generate NTCs.

3. A Definitive Interconnection System Impact Study (DISIS) agreement for the generation resource has been executed, an interim GIA has been requested, and a GIA will be entered into when applicable.
4. An RFP for the generation resource has been awarded, if applicable.

2.1.2 LONG-TERM FIRM TRANSMISSION SERVICE

SPP long-term Point-To-Point and Network Integration Transmission Service commitments are generally modeled at expected usage of firm transmission service reservations in each year and season, as supplied by SPP stakeholders during the SPP modeling process. Commitments with external entities are coordinated with those entities through the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG).

The modeling of long-term firm transmission service in the base reliability models will result in a change in generation dispatch for the defined source and sink of the service and will vary by season, year and generation type.[9] All DC tie set points will be modeled with expected usage for the season as submitted by stakeholders, not exceeding long-term firm transmission service. Resources related to a long-term firm transmission service reservation with a single plant as the source will be dispatched to meet the modeled usage. Conventional resources related to long-term firm transmission service reservations with a fleet of resources as the source will be dispatched based on economic merit order within each resource fleet, as needed to serve the service commitments and applicable load. The fleet of conventional resources will be dispatched after renewable resources. Renewable resources will be dispatched based upon the following seasonal methodologies[10]:

- Light load models:
    - Wind resources: Dispatch to 100 percent of each facility's long-term firm transmission service amount.
    - Solar resources: Dispatch to zero MW regardless of the facility's long-term firm transmission service amount.
    - Battery resources: Dispatch of battery resources with long-term firm transmission service for purposes of charging will be set to a negative MW amount not to exceed the facility's charging firm service amount or the Pmin (max charging capability). Batteries without firm service for purposes of charging will be set to neutral or zero output with online status. Note that the battery acts like a load in the model when dispatched to a negative MW amount.
- Peak models: Output of renewable resources with long-term firm transmission service will be modeled in the base reliability model at each facility's latest five-year average (or replacement data if unavailable) for the applicable seasonal SPP coincident[11] peak, not to exceed each facility's firm service amount.

[9] Resources may be added to a source or sink definition if the requirements of the Generation Resources section are met.
[10] The renewable dispatch methodology may necessitate a change to the modeled expected usage of firm transmission service.
[11] SPP coincident peak equals the highest demand including transmission losses for energy measured over a one clock hour period during the defined season.

Replacement data may be necessary to determine the dispatch amount for each renewable resource type if the resources have less than five years of data available. SPP will calculate the replacement data for use in the methodology for the peak models.

To calculate the replacement data, SPP will determine for each renewable type the amount of renewables being dispatched in each SPP coincident peak hour located within each state, then divide by the total amount of long-term firm transmission service sold on those renewable resources. This will provide a percentage of MW within each state dispatched during the SPP coincident peak hour. This calculation will be done for the five previous years. SPP will average the data together to develop a flat percentage value for each state. These state average values for each renewable type will be the replacement value for each renewable resource requiring replacement data located within that state to give each renewable resource five years of data.

For load pseudo-tied into the SPP BA, SPP will coordinate with the external entity and the owner of the load to model the long-term firm transmission service in the planning models as follows:

- Firm Point-To-Point Transmission Service: Model up to the long-term firm transmission service amount
- Network Integration Transmission Service: Model up to the firm load amount

2.1.3 LOAD FORECASTS

The ITP assessment will require load forecasts for SPP TOs and stakeholders 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 SPP using the process described in the Model Development Procedure Manual[12]. The load will represent each individual load-serving entity's peak conditions without losses per season (*i.e.*, non-coincident conditions for the SPP region).

2.1.4 TOPOLOGY

The topology used to account for the SPP transmission system, excluding future generation resources and associated interconnection facilities, will be the existing transmission system and any upgrades or facilities that are included in the SPP Transmission Expansion Plan (STEP) and have been approved for construction.[13] In-service dates of upgrades with NTC/NTC-C should be consistent with the latest information supplied by the transmission owner in the project tracking process. Upgrades that have met the requirements for NTC withdrawal or reevaluation will be excluded from the base reliability model as specified in SPP business practices.

The base reliability models will be developed to reflect the expected state of the transmission system over the long-term horizon. Transmission outages known during the annual model building process that meet NERC TPL-001 requirements shall be modeled. Transmission outages that do not meet NERC TPL-001 requirements will not be modeled. Temporary facilities shall not be modeled and transmission lines operated in real-time as normally open shall be modeled as normally open.

For topology updates outside the SPP footprint, the Eastern Interconnection model areas will be obtained from the latest ERAG MMWG model set. SPP will coordinate with the appropriate external entities and request applicable first-tier planned upgrades that should be included in the models.

[12] MDAG Model Development Procedure Manual
[13] This includes upgrades identified through the generator interconnection process and those approved by Southwestern Power Administration.

2.1.4.1 Phase-Shifting Transformers

PSTs will be modeled in accordance with the guidelines documented in the MDWG Manual.[14]

2.1.5 EXTERNAL TRANSACTIONS

Transaction data between entities external to the SPP footprint, not including those with transmission service with SPP, will be obtained directly from the external entity, if available, or from the latest ERAG MMWG models that most closely align with the corresponding study year models.

2.1.6 BASE RELIABILITY MODEL APPROVAL

All data requests and review opportunities for the ITP base reliability model set and ITP short-circuit model(s) will be administered through the TWG, and the TWG will approve the base reliability and short-circuit models.

ITP base reliability model development deadlines are established with MDAG stakeholder coordination and approval. Unless alternative base reliability data submission deadlines are established under the approved ITP Scope, the MDAG Model Development Procedure Manual model build schedule identified deadlines establishes the initiating point for late data submission under Section 10.3.

2.1.6.1 Topology and Rating Finalization Pass

After completion of the associated MDAG Model Development Procedure Manual model build schedule, base reliability models may be updated for topology and rating information that does not significantly impact the economic model development process. This update will occur when models are updated with the latest ITP project portfolio for the final reliability assessment milestone. Updates will also be included in the economic model. Topology and rating data updates may include the following modeling items:

- Buses
- AC transmission lines
- HVDC transmission facilities
- Transformers
- Reactive Power Compensation Static VAR Systems (SVS)

The topology and ratings finalization pass is included within the schedule section of the ITP Scope document.

After the model sets are finalized for the ITP assessment, no topology and ratings changes will be accepted to update the model. Any identified topology and ratings changes will be required to be submitted during the detailed project proposal (DPP) window as detailed in Section 5.1.1.3.

2.2 MARKET ECONOMIC MODEL OVERVIEW

Each Market Economic model simulation is an hourly security-constrained unit commitment and economic dispatch utilizing a DC representation of the transmission system.

The assumptions for each of the economic models are detailed later in this section.

[14] MDAG Model Development Procedure Manual

2.2.1 MODEL ASSUMPTIONS AND DATA

2.2.1.1 Future Development

Due to the uncertainties involved in forecasting future system conditions, a number of diverse futures will be considered that take different assumptions into account. Consideration of multiple futures allows 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 SPC and the TWG and will be subject to the approval of MOPC.

Economic models will be developed for three study years (years 2, 5, and 10). A single future will be developed for year 2, 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 5 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, and up to two additional futures designed to assimilate expected or plausible future scenarios. Details about the reference case and any other 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 will solicit stakeholders for potential public policy drivers to be considered in the study through a survey within the SPP annual data request. Timing for the submission of public policy drivers that SPP stakeholders request to be considered shall be included in the study schedule. Any drivers requested to be considered by SPP stakeholders that are excluded from the study, as well as an explanation for the exclusion, shall be detailed in the ITP assessment report.

2.2.1.2 Load and Energy Forecasts

The ITP assessment 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-serving entity'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 development process, SPP will obtain load data to utilize in the ITP assessment by the following unless directed otherwise by the ESWG:

- 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 third-party vendor data. If the primary source is not available or is not appropriate, SPP will create a synthetic load shape based on historical data points and FERC Form 714 information.
- Monthly peak and energy percentages: The primary source shall be third-party vendor data. If the primary source is not available or is not appropriate, SPP will calculate the monthly peak and energy percentages by using hourly load shape data.
- Load factor: As a primary source, annual load factors shall be provided by SPP stakeholders. If the primary source is not available or is not appropriate, SPP will calculate load factors by utilizing hourly load shapes.

- Transmission loss factor: As a primary source annual loss factors shall be provided by SPP stakeholders. If the primary source is not available or is not appropriate, SPP will utilize previous ITP study values.
- Demand mapping: The primary source shall be the economic load ownership legend[15] reviewed as part of the SPP annual data request. If the primary source is not available or is not appropriate, SPP stakeholders will provide load bus and ID mappings to demand groups.
- Resource planning peak load: A separate, optional load forecast, reflecting the no-loss aggregated bus load totals (MW), and which includes controllable load curtailing programs. This forecast will be used for the conventional resource plan.
- Resource planning load factor: Load factor associated with resource planning peak load. This load factor will be used for the conventional resource plan.

External region load forecasts will be taken from the base reliability model set and each region will be allowed to review load forecast data prior to use in the ITP assessment. If readily available and appropriate, load forecasts from the most current neighboring entity's study will be used for their region in the ITP assessment in place of the base reliability model data. The use of their load forecast will be future specific. If there is not a future comparable to the ITP future, as determined by SPP and the ESWG, the load forecast would be determined utilizing base reliability model data. The data sources approved by the ESWG to be used will be documented in the study report.

2.2.1.3 Renewable Policy Review

After the forecasted load is finalized, renewable policy standards (RPS) will be assessed for utilities within the SPP footprint. The ITP study scope will detail mandate and goal values for each utility 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 previous ITP study's mandate and goal values will be used as a starting point for the current study's calculations. Any changes to these values will be reviewed by the CAWG and approved by the ESWG. Ultimately, the renewable policy review results will be reviewed by the CAWG and approved by the ESWG. The values for mandates and goals will consider forward-looking legislation set by the states that either should be or must be met, depending on the state, in years 5 and 10. Both capacity- and energy-based mandates and goals will be assessed for fulfillment during development of the resource plan. Those that are energy-based also will be assessed during the policy needs assessment.

Renewable energy credits will be accommodated appropriately as provided to SPP.

If any significant changes to renewable mandates or goals occur during an ITP assessment, SPP 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

[15] Table within the SPP annual data request that maps loads according to their attributes to groups of demands for the economic model

cost prohibitive or municipals are exempt), those exemptions will be considered as SPP is notified during the renewable policy review.

2.2.1.4 Generation Resource Inclusion

Generation resources included in the base reliability model will be incorporated into the economic model, as appropriate.[16] Resources identified by SPP as necessary to solve the base reliability model shall not be included in the economic and powerflow models, unless the resources meet the requirements of adding generation described in this section.

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

1. A formal request has been sent to SPP[17] requesting the generation capacity be included.
2. The generating resource has an effective GIA that is not on suspension or an effective interim GIA.
3. 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 for review and approval. The request may be made by either a stakeholder or SPP. Additional generation resources to be considered for inclusion in the economic model may have, but are not limited to, all or a subset of the following attributes:

1. Registered in the SPP Market;
2. Expected to be in service within two years of the study year;
3. Have a good standing GIA; not on suspension;
4. Have cost allocation amounts from assigned network upgrades that total to less than $100 million out of Generation Interconnection Studies;
5. A DISIS agreement for the generating resource has been executed, an interim GIA has been requested, and a GIA will be entered into, when applicable; or
6. An RFP for the generating resource has been awarded, if applicable.

TWG will review the requests and provide any feedback to ESWG prior to the ESWG's review. Approved generating resources will be added to the applicable economic model based on the expected in service date. All other resource expansion needs will be determined through the SPP resource expansion planning process as detailed in the Resource Expansion Plan section.

2.2.1.5 Generation Resources

Third-party vendor data will be used as the starting point for generation parameters needed for the economic model set. Data related to the physical characteristics of generators will be reviewed and

[16] 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.
[17] Submitted through SPP RMS

updated as needed by the SPP stakeholders to provide company-specific values through the SPP annual data request.

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

- Generator name
- 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

2.2.1.6 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 Base Reliability Model Overview section with the following exceptions:

- 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 as forecasted by the data submitting entity will not be included.

2.2.1.6.1 DC Lines

DC lines are included in the economic model through an import of the base reliability powerflow data. The range of allowable hourly operation will be based on:

- Operational practice (current or future expected), and
- Expected flows from the SPP powerflow models.

2.2.1.6.2 Phase-Shifting Transformers

In the Market Economic models, SPP phase-shifting transformers (PSTs) with auto-adjust enabled in the Base Reliability models may adjust up to the full angle range. For PSTs with auto-adjust disabled, the PSTs will be modeled at a fixed angle, unless determined otherwise by the TWG and ESWG.

2.2.1.6.3 DC Ties

For direct current (DC) ties that connect SPP to the Texas and western interconnections, hourly profiles will be developed based on at least three years of historical flows across each DC tie and will be capped at long-term firm transmission service amounts. These transactions will be modeled as fixed with no assumed curtailment price.

2.2.1.7 Fuel Prices

Fuel price forecasts for the reference case future, including oil, uranium, coal, and associated transportation costs, will be based upon the selected vendor's latest dataset identified by SPP and approved by ESWG. Natural gas price forecasts will be determined from multiple reputable fuel forecast datasets identified by SPP, approved by the ESWG and documented in the respective approved ITP assessment scope.

2.2.1.8 Emission Prices

Emission price forecasts for the reference case future, including 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.

2.2.1.9 Hurdle Rates

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

2.2.1.10 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 price at which the resource will curtail. If the locational marginal price (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 prices impact the dispatch of wind and solar units in the economic models but do not impact the operating cost of the units.

To model a curtailment price reflective of market operation for wind and solar units, current IRS legislation will be utilized to account for projected production tax credit (PTC) impacts.

Both existing and projected wind and solar units will have a negative curtailment price[18] that reflects the "grossed-up" value of a PTC[19] in accordance with applicable laws and regulations. Investment tax credits (ITC) will not be considered in the adjustment of curtailment prices unless

[18] The negative curtailment price will be adjusted for inflation to the study year using a typically assumed inflation rate for the study.
[19] Reflecting a IRS published PTC value and federal corporate income tax rate at the commencement of the study where the "grossed-up" PTC value = PTC/(1-corporate tax rate)

defined in the ITP Scope. If no PTC nor ITC is applicable, existing and projected units will have a $0/MWh curtailment price.

For the purposes of applying the above curtailment price modeling criteria to additional wind and solar amounts determined by the Renewable Resource Expansion Plan, SPP and the ESWG will estimate the additional wind and solar amounts per year and use information from the Resource Siting Plan to determine appropriate curtailment price methodology for additional units.[20]

If any significant changes to the PTC rules occur during an ITP assessment, SPP staff or stakeholders can bring information to the ESWG for review and potential approval for use in the ITP assessment. Any resulting deviations from this standard curtailment pricing will be noted in the study report.

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

For all wind and solar units, the VOM shall be $0/MWh to reflect the low operating cost of renewable resources.

2.2.1.11 Must Run Units

Must-run units in the ITP assessment are dispatched during all available hours to 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 identified by SPP or stakeholders during the generation review and subject to approval by the ESWG.

2.2.2 RESOURCE PLAN

2.2.2.1 Resource Expansion Plan

After forecasted load and existing and planned generation have been defined through the SPP annual data request, analysis will be conducted to determine new (conventional and renewable) resource additions required in years 5 and 10 for each future in the economic and Market Powerflow model. Resource additions are included 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 2 models will be assessed to evaluate whether the reserve margin requirements are being met at the SPP BA level.

2.2.2.1.1 Renewable Resource Expansion Plan

SPP shall develop a resource plan to meet renewable expectations for the region. This will include capacity as required through the renewable policy review, as well as capacity identified through criteria developed by SPP and stakeholders. Consideration will be given to the futures being studied

[20] For example, approximate projected wind amounts per year can be determined from existing wind amounts and projected wind amounts by linear interpolation or other means and wind site rankings from the Resource Siting Plan can be used by assuming highest rank sites receive earlier in-service dates.

and factors such as government regulations, historical trends, natural gas prices, installation trends, integrated resource plan projections, and SPP stakeholder feedback.

Renewable additions will be computed using criteria that can be applied uniformly across pricing zones.[21] For example, each pricing zone should 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. An appropriate resource plan from the most current external entity's study will be used for their region in the ITP assessment, if readily available and appropriate. These resource plans are future-specific.

If there is not an appropriate or available resource plan of a future comparable to a given ITP future, as determined by SPP and the ESWG, these renewable additions shall be determined by SPP and the ESWG in each study. Consideration will be given to the futures being studied and factors such as government regulations, historical trends, natural gas prices, installation trends (nationwide and location-specific), integrated resource projections, and feedback from external entities.

2.2.2.1.2 Conventional Resource Expansion Plan

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 in effect at the commencement of the resource planning milestone of the study.

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

SPP will identify the optimal mix of new conventional resource additions needed in all futures for the SPP region. The ESWG will review and approve the methodology for development of resource plans for each new ITP study with decisions documented in the Study Scope Document. The magnitude of resource additions will be based on resource shortfalls. Ownership of conventional unit additions 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 to avoid excessive additions of new resources to individual pricing zones.

External regions also will be analyzed for resource shortfalls. An appropriate resource plan from the most current neighboring entity's study will be used for their region in the ITP assessment, if readily available and SPP 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 SPP and the ESWG, then conventional additions to address shortfalls shall be added to external regions with a

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

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% combined cycles and 40% combustion turbines, a ratio as close as possible to this 60/40 ratio would be used to guide conventional resource additions in external regions.

2.2.2.2 Resource Siting Plan

2.2.2.2.1 Siting Process

The resource plan will identify resource additions that need to be sited to meet study objectives. A spatial location and electrical point of interconnection for each new resource within the SPP region will be selected. This effort will be conducted as a screening level exercise to identify sites and will not be intended to provide or replace a fully scoped power-plant siting study. Siting guidelines are documented in the Resource Siting Manual[22], which is owned and approved by the ESWG and the TWG.

2.2.2.2.2 Site Repository

The site repository stores sites, usage, suitability attributes, prioritization, and SPP stakeholder feedback from study to study. Each site is classified by technology type and includes applicable qualitative and quantitative site suitability attributes and qualifications. The Resource Siting Manual will detail how sites will be prioritized and ranked.

2.2.2.2.3 Process Flow

The siting process will generally adhere to all of the following steps:

1. Update the site repositories with the latest powerflow and generator interconnection queue information to account for actual resource development between planning cycles.
2. Post repositories and request applicable SPP stakeholders to provide feedback and additional sites for consideration and supportive rationale.
3. Assess whether the site repositories include an adequate and diverse amount of sites to fulfill the requirements of the resource plan and are representative of remaining technical renewable potential across the SPP region.
4. Develop additional conventional resource sites and conceptual solar and wind sites as needed.
5. Rank and select sites.
6. Post site prioritization and selections for review.
7. Make any necessary adjustments and repost for approval.

2.2.2.2.4 Siting for External Regions

The resource siting plan for each of the modeled regions external to SPP will be based on the corresponding company's resource plan in their most current regional planning study, as available and appropriate. If this data is not available or appropriate, as determined by SPP and the ESWG, SPP will coordinate with the corresponding entity to closely resemble the same logic as those sited through the SPP siting plan.

2.2.2.3 Generation Outlet Facilities

Once the resource and siting plans have been finalized, SPP will reconsider the First Contingency Incremental Transfer Capability analysis completed during the siting process to develop any

[22] Resource Siting Manual

necessary generator outlet facilities (GOFs). This GOF process is intended to proxy the evaluation of a resource in the generator interconnection process to develop necessary upgrades.

Transmission distribution factors (TDFs) will be calculated for each transmission facility with each generation resource at its full nameplate value under system intact and contingency conditions. Overloaded lines with a TDF above the threshold used in the generator interconnection process will be used as an indicator that a GOF may be necessary. In the instance that multiple resource plan units are sited with electrically similar interconnection points, the TDFs will be calculated with each resource dispatched at maximum capacity simultaneously to ensure the final GOF is sized appropriately.

When TDFs on overloaded transmission facilities meet or exceed the minimum threshold, GOFs will not be guaranteed for inclusion in the ITP models. SPP will use engineering judgment, such as the consideration of a unit's expected dispatch and the impact a GOF may have on potential economic and/or reliability needs, to recommend GOF inclusion.

All GOFs recommended for inclusion in the models will be reviewed and approved by the TWG.

2.2.3 CONSTRAINT ASSESSMENT

SPP maintains a list of flowgates to monitor based on reliability and economic issues seen in real-time. The constraint assessment is used to identify potential future constraints for each future and year of study.

To create these additional constraints, SPP will perform economic simulations to identify additional or breaching elements in the system that occur during the reliability peak and off-peak hours[23]. System flows under two levels of constraint will be analyzed:

- Copper Plate: No defined constraints.
- Initial constraint list based on NERC and SPP permanent and temporary[24] flowgates.

2.2.3.1 Contingency Screening

Due to software and time limitations, large contingency lists are not feasible. The contingency lists will be created with the goal of including the most impactful contingencies for constraint identification.

After the initial economic simulation dispatch results have been created, the resulting contingencies will be limited to the following types of planning events identified in the NERC Standard TPL-001 for the 100 kV-and-above transmission system:

- P1.2 and P1.3 single-branch contingencies on the 100 kV and above system exceeding 50 percent loading in the peak and off-peak hours under system intact conditions for the translated areas.
- P1.2 and P1.3 single-branch contingencies on the 200 kV and above system exceeding 10 percent loading in the peak and off-peak hours under system intact conditions for the SPP footprint.

[23] Defined in the Market Powerflow Model Overview section

[24] Temporary flowgates included in the initial constraint list will be based on engineering judgement. This includes, but is not limited to, temporary flowgates associated with an economic operational need.

- Contingencies included in the SPP permanent and temporary flowgates, including P7 events.
- Other P1, P2, P4 and P5 events as potential contingencies.

Contingencies meeting these criteria that are inconsistent with operation of the SPP Integrated Marketplace or create simulation anomalies may be excluded from further evaluation.

2.2.3.2 Constraint Identification

Facilities exceeding their thermal limits under system intact and contingency conditions will be assessed for potential inclusion as constraints. Flow violations occurring in either of the reliability hours will be automatically included unless SPP and stakeholders deem otherwise during the constraint review. Flow violations occurring in the annual hourly simulations will be considered for inclusion based on the following information, at a minimum:

- Number of violation hours and/or violation loading thresholds.
- The ability of the simulation to reach a valid[25] dispatch solution due to a given constraint[26].
- Preliminary economic model simulation results.
- Performance of constraints in prior SPP expansion plan studies.

The ESWG and TWG will be given the opportunity to review the resulting constraints. After the review is completed, TWG approval will be requested before completion of the milestone.

In addition to the approved list of constraints, some 69 kV constraints may be included in the constraint list as needed to properly control the dispatch of resources on the 69 kV system and capture congestion in developing 100 kV and above solutions. These constraints will be suggested or provided by SPP stakeholders.

2.3 MARKET POWERFLOW MODEL OVERVIEW

Each Market Powerflow model is an AC powerflow representation of a specific one-hour snapshot of a Market Economic model simulation with SPP acting as its own balancing authority. Each Market Economic model developed for the ITP assessment will have two corresponding AC powerflow models representative of system conditions of those hours within the year. The peak hour will be the hour with the highest total megawatt output of wind resources within SPP selected from the top 1% of SPP coincident peak load hours. The off-peak hour will be the hour with the highest wind penetration between April and May between the hours of 12 a.m. – 6 a.m. (off-peak).

The models will be developed by matching the dispatch and load in each Market Powerflow model to the dispatch and load in the respective hour of the economic model simulations. This process will be described later in the DC/AC Conversion section. After the conversion is complete, SPP and stakeholders will assess reactive power flows on the system that the economic modeling tools are unable to represent. Some of the Market Powerflow models will be used to meet the requirements of a sensitivity case necessary for NERC Standard TPL-001 compliance.

The system operating points for the peak and off-peak AC powerflow will be consistent with the corresponding hours of the economic model simulations utilized in the economic analysis.

[25] All constraints and generating parameters honored

[26] A constraint may be removed and considered as a reliability need during the Market Powerflow analysis

2.3.1 DC/AC CONVERSION

2.3.1.1 Generation

Unit commitment and dispatch will be determined in the economic model simulation to derive an hourly generation profile for the simulated system. For development of the Market Powerflow model, this simulation will not include generator-forced outages and will account for approximated transmission losses modeled in the economic model at the load buses.

The following parameters will guide how the resource plans, both internal and external, are modeled with regards to reactive settings. Stakeholders are given the opportunity to review certain reactive device settings during the Market powerflow model review period described in Section 2.3.2 of the ITP Manual.

All resources (excluding distributed generation such as rooftop solar) included in the internal or external resource plans will be modeled as directly injecting power at the point of interconnection (i.e. ESWG approved site). Maximum and minimum reactive capability of generators will be determined by utilizing a 0.95 power factor and the maximum real power capability of the resource. Resources sited where existing generation is already interconnected will follow the voltage schedule and remote bus determination of the existing plant. The following information is resource fuel type specific and references settings observed in the powerflow modeling software utilized in the ITP process. The following settings apply to both the internal and external resource plans, unless determined otherwise by the TWG.

Conventional Generation

The control mode for conventional generation will be set to 'Not a wind machine'. The voltage schedule (i.e. vsched) will be set at 1.015 per unit for system peak models and 1.00 per unit for off peak models, unless a voltage set point warning is observed. For sites with no existing generation, the remote bus will be the point of interconnection of the new resource. Adjustments to the voltage schedule may be made on a case by case basis due to nearby existing generators.

Solar, Wind, or Energy Storage Resources

The control mode for utility scale renewable and energy storage resources will be '+ or – Q limits based on WPF. WPF will be set at .95. The voltage schedule will be set at 1.015 per unit for system peak models and 1.00 per unit for off peak models, unless a voltage set point warning is observed. For sites with no existing generation, the remote bus will be the point of interconnection of the new resource. Distributed generation will be modeled at a 1.0 power factor. Adjustments to the voltage schedule may be made on a case by case basis due to nearby existing generators.

2.3.1.2 Load Forecasts

Hourly load values will be calculated for each defined group of demands in the economic model simulation considering annual peak demand and energy, monthly allocations of demand and energy, and the hourly load shape. The resulting load for each group of demands in each hour will be allocated on a pro-rata basis to the individual bus loads assigned to that demand group. The real power demand for each reliability hour will be incorporated into the AC powerflow models directly from the economic model simulation output. Reactive power demands will be calculated for each bus load based on the power factor of the equivalent load in the respective base reliability model.

2.3.1.3 Interchange

Economic model simulation will determine the exchange of energy between SPP and neighboring systems.

2.3.2 REACTIVE DEVICE SETTINGS

After the DC/AC conversion process is complete, SPP and stakeholders will have an opportunity to review the settings for transmission facilities that provide reactive support for the transmission system. SPP stakeholders will submit changes to set points for capacitors, reactors, tap changers for transformers, remote buses, 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 SPP and stakeholders that potential violations are based on realistic system conditions prior to the reliability needs assessment.

After all reactive device setting adjustments have been received, SPP will apply the adjustments to the appropriate models before final posting and approval by the TWG.

2.4 OPERATIONAL MODEL DEVELOPMENT

SPP will identify case(s) in which the reliability and manual commitment economic operational needs are present to evaluate whether the needs are addressed with proposed solutions. SPP may develop ITP planning models to replicate congested economic operational needs for solution evaluation as described in the Persistent Operational Solution Evaluations section.

2.5 INTERREGIONAL COORDINATION

During the development of each ITP model, SPP will work with external entities to acquire necessary modeling information. Where appropriate, information from recent interregional planning processes will be leveraged. External entities will be given the opportunity to review the models concurrent with SPP stakeholders.

3 BENCHMARKING

3.1 POWERFLOW MODEL

An ITP powerflow model will be validated against SPP operational data, which may include a comparison of topology and ratings. ITP powerflow models will be benchmarked against the previous study models, which may include a comparison of topology, generation, load, ratings, and area interchange.

3.2 ECONOMIC MODEL

The year 2 economic model will be utilized to validate modeling parameters to determine if operation is reflective of the SPP system. Data validation may include: temporary flowgates, capacity factor by unit type, maintenance outages, operating and spinning reserves, average energy costs, 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.

4 NEEDS ASSESSMENT

SPP will conduct economic, reliability, public policy, and operational needs assessments, as detailed in this section, which will result in a comprehensive list of needs to be posted for SPP stakeholders. The Solution Development and Evaluation section further describes the development and submittal of solutions to this needs list.

4.1 ECONOMIC NEEDS ASSESSMENT

The economic needs assessment will be performed in parallel with the reliability, public policy, and operational needs assessments. The economic needs of the system will be identified for each future and study year. Economic model simulations derive 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 the additional cost of dispatching around those constraints. This is the starting point for constraints to be considered for economic needs for the study.

4.1.1 SCUC & SCED ANALYSIS

The economic needs of the system will be identified 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. During the SCUC, 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). The SCUC does not explicitly consider 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 simulation will solve using nodal LMPs, 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.

4.1.2 NEED IDENTIFICATION

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 a given constraint's average shadow price[27] and the number of hours that constraint is binding.

Figure 2: Congestion Score Formula

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, additional constraints may be included if SPP determines the inclusion would better define an economic need overall.[28]
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 determines the constraints are related to a target area or a historically congested market-to-market flowgate and warrant further analysis.[29]

[27] The shadow price represents the potential reduction in total SPP production costs if the limit on a congested flowgate could be increased by 1 MW.
[28] 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.
[29] Potential benefit is determined by relaxing the rating of the monitored element of a flowgate to relieve congestion.

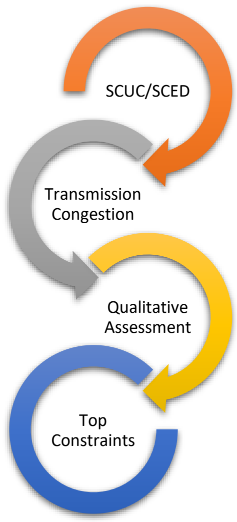

Figure 3: Economic Need Development

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

- Each other
- Integrated Marketplace congestion[30]
- Operational issues
- Regional Cost Allocation Review (RCAR) issues
- Seams issues
- Operational, reliability, and/or policy needs
- Generator interconnection and transmission service study queue limitations
- Transmission corridors with limited capacity
- Power transfer distribution factor flowgates used to represent thermal, stability, or contractual limitations
- Facilities that are thermally limited by terminal equipment

In the analysis portion of this milestone, all needs will be reviewed to determine the underlying 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 identifying the drivers for each need.

A more qualitative assessment may be used to limit the number of needs to meet the study schedule and objectives. This assessment will consider the number of binding constraints with similar

[30] SPP 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.

attributes, recommended constraints, and/or target areas for additional analysis, mitigation need dates, general transmission solution lead times, and other project staging considerations.

As part of the needs posting, SPP will provide general explanations and rationale surrounding the grouping of constraints as well as high-level scopes for any necessary additional analysis to be performed on economic needs to develop a recommended portfolio of projects.

Economic issues in the first-tier areas may be included in the needs list along with an indication that there is potential for seams solutions.

4.2 RELIABILITY NEEDS ASSESSMENT

The reliability needs assessment will be performed in parallel with the economic, public policy, and operational needs assessments. All needs will be identified by assessing the performance of the SPP transmission system under system intact and contingency conditions. SPP will utilize Table 1 from the NERC Standard TPL-001 as the basis for the contingencies to be assessed during the study. Contingencies that do not allow for non-consequential load loss (NCLL) or the interruption of firm transmission service (IFTS) will be analyzed during the reliability needs assessment. SPP Planning Criteria[31] will be utilized to determine if a potential regional reliability violation will be considered as a reliability need.

Thermal violations identified in the Market Powerflow model during the reliability assessment may not have met the constraint assessment criteria to be defined as a constraint or may be related to a defined constraint in the economic model. Reliability needs will be evaluated for reclassification as an economic need during or after the needs assessment to ensure proper evaluation of system needs. If reclassification is justified, SPP will inform stakeholders via email or the SPP website.

4.2.1 BASE RELIABILITY MODEL

Contingency analysis for the base reliability model will consist of analyzing P0, P1, and P2.1 planning events identified in NERC Standard TPL-001 Table 1 for each of the models. The voltage level for monitored and contingent elements in the SPP footprint are described in more detail in Table 2.

[31] SPP Planning Criteria

	P0, P1, P2.1	
	Monitored Element	Contingent Element
Year 2 Summer	69 kV +	69 kV +
Year 2 Winter		
Year 2 Light Load		
Year 5 Summer		
Year 5 Winter		
Year 5 Light Load		
Year 10 Summer	100 kV+[32]	100 kV+[31]
Year 10 Winter		
Year 10 Light Load		

Table 2: NERC Standard TPL-001 Planning Events as Monitored and Contingent Elements

The base reliability models will be analyzed with the remaining contingencies from Table 1 in the NERC Standard TPL-001 that do not allow for NCLL or IFTS as detailed in Table 3.

	Other Planning Events[33]	
	Monitored Element	Contingent Element[34]
Year 2 Summer	100 kV+	100kV/300 kV+
Year 2 Light Load	100 kV+	100kV/300 kV+
Year 5 Summer	100 kV+	100kV/300 kV+
Year 10 Summer	100 kV+	100kV/300 kV+

Table 3: Remaining Contingencies for Monitored and Contingent Elements

4.2.2 MARKET POWERFLOW MODEL

Contingency analysis for the Market powerflow models will consist of analyzing P0, P1, and P2.1 planning events identified in NERC Standard TPL-001 Table 1 for each of the models. The voltage level for monitored and contingent elements in the SPP footprint are described in more detail in Table 4.

[32] In addition, 69 kV facilities will be both contingent and monitored elements for informational purposes only. This data will inform the solution and portfolio development process to ensure solutions can mitigate violations for the entire study period.
[33] Other planning events include P2.2, P2.3, P3.1-P3.5, P4.1-P4.5, and P.5
[34] Some planning events allow/disallow NCLL or IFTS based upon the voltage level of the contingent element.

<table>
<tr><th></th><th colspan="2">P0, P1, P2.1</th></tr>
<tr><th></th><th>Monitored Element</th><th>Contingent Element</th></tr>
<tr><td>Reference Case Year 2 Peak</td><td rowspan="4">100 kV+ with select 69 kV facilities</td><td rowspan="4">100 kV+ with select 69 kV facilities</td></tr>
<tr><td>Reference Case Year 2 Off-Peak</td></tr>
<tr><td>Reference Case Year 5 Peak</td></tr>
<tr><td>Reference Case Year 5 Off-Peak</td></tr>
<tr><td>Reference Case Year 10 Peak</td><td rowspan="6">100 kV+</td><td rowspan="6">100 kV+</td></tr>
<tr><td>Reference Case Year 10 Off-Peak</td></tr>
<tr><td>F_X Year 5 Peak</td></tr>
<tr><td>F_X Year 5 Off-Peak</td></tr>
<tr><td>F_X Year 10 Peak</td></tr>
<tr><td>F_X Year 10 Off-Peak</td></tr>
</table>

Table 4: NERC Standard TPL-001 Planning Events as Monitored and Contingent Elements

The remaining contingencies in Table 1 of the NERC Standard TPL-001 that do not allow for NCLL or IFTS will be analyzed if a violation was observed in the same year/season of the base reliability model as detailed in Table 5.

	Other Planning Events[35]	
	Monitored Element	Contingent Element[36]
Reference Case Year 2 Peak	100 kV+	100kV/300 kV+
Reference Case Year 2 Off-Peak	100 kV+	100kV/300 kV+
Reference Case Year 5 Peak	100 kV+	100kV/300 kV+

Table 5: Remaining Contingencies for Monitored and Contingent Elements

4.2.3 NON-CONVERGED CONTINGENCIES

SPP will use engineering judgment to resolve non-converged cases from the contingency analysis. If these contingencies cannot be solved, the potential violations will be identified as reliability needs along with the result of the analysis (e.g. voltage collapse).

4.2.4 FIRST-TIER CONSIDERATION

During the reliability needs assessment, first-tier areas will be monitored to identify potential reliability needs. After vetting with the appropriate neighboring entity and receiving their consent, first-tier potential issues will be posted in conjunction with the SPP needs list. The first-tier potential issues list will not serve as solicitation of SPP stakeholders for solutions to address first-tier issues, but the list will be used to evaluate whether there are solutions that address SPP and first-tier issues concurrently.

4.2.5 VIOLATION FILTERING

SPP will review the list of potential violations to determine the list of valid violations that will be included in the needs assessment.

As part of the violation filtering, observed thermal overloads in the Market models will receive additional review. The SCUC/SCED simulations honor identified constraints by limiting the dispatch potential of the fleet of generation resources, ensuring constraints will not be overloaded. In theory, a thermal violation should only be considered a reliability need if a constraint was not modeled or breached its thermal limit in the economic simulation. In the instance that an economic constraint or similar monitored element/contingency element pair (mon/con pair) is identified as a thermal overload in the AC contingency results, it will be invalidated as a reliability need. Invalidating these type of thermal overloads will allow the economic potential of the constraint(s) to be evaluated to determine if cost-beneficial solution is available.

4.2.6 ZONAL PLANNING CRITERIA

Zonal Planning Criteria (ZPC) will be collected in accordance with the SPP tariff. Voltage-based ZPC that is more stringent than the criteria specified in the SPP Planning Criteria will be utilized during

[35] Other planning events include P2.2, P2.3, P3.1-P3.5, P4.1-P4.5, and P.5
[36] Some planning events allow/disallow NCLL or IFTS based upon the voltage level of the contingent element.

the needs assessment to identify potential Order 890 criteria violations.[37] For any ZPC violations exceeding non-voltage-based criteria, TOs will submit the following to SPP via RMS in accordance with the SPP tariff and ITP study schedule:

- ZPC exceedance,
- Methodology used to identify the ZPC exceedance,
- Supporting information used to determine the ZPC exceedance, and
- Viable solutions to the ZPC exceedance.

SPP will review the submitted ZPC exceedances and post the confirmed ZPC exceedances on a secure SPP website at the time of the ITP needs assessment posting.

4.2.7 SHORT-CIRCUIT ANALYSIS

All short-circuit needs will be classified as reliability needs and will be identified by determining maximum available fault current on the SPP transmission system compared to the respective equipment fault-interrupting duty capabilities under system intact conditions. SPP will monitor all bulk electric system and SPP tariff facilities for the short-circuit analysis.

A year 2 summer peak ITP model will be developed for the short-circuit analysis. This short-circuit model differs from the powerflow models in that all modeled generation and transmission equipment are placed in operation to simulate the maximum available fault current.

SPP will simulate three-phase faults and single line-to-ground faults and provide the following analysis results to the TOs as requested:

- Full bus-fault current and line-out results using an automatic sequencing fault calculation
- Full bus-fault current and line-out results using an American National Standards Institute fault calculation

The TOs will be required to evaluate the results and respond to SPP if any fault-interrupting equipment will have its duty ratings exceeded by the maximum available fault current (potential violation). For equipment that is seen to have its duty rating exceeded, the TO will provide SPP with the applicable duty rating of the equipment.

Potential violations of SPP tariff facilities will be identified as a need to be included in the needs assessment. SPP will work directly with the facility owners on all remaining potential violations to ensure that proper mitigation of issues is completed.

4.3 PUBLIC POLICY NEEDS ASSESSMENT

The public policy needs assessment will be performed in parallel with the reliability, economic, and operational needs assessments, 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

[37] Order 890 criteria violations are potential violations identified pursuant to FERC's nine planning principles, which are coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.

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.

4.4 PERSISTENT OPERATIONAL NEEDS ASSESSMENT

Persistent operational needs may be either economic or reliability related. The criteria for identifying these needs is described in this section. SPP may propose additional needs to account for operational issues not meeting the criteria thresholds or other problematic operational issues observed in operating the transmission system not fitting the given criteria. These additional needs will be presented to the ESWG and TWG for review and endorsement.

4.4.1 ECONOMIC OPERATIONAL NEEDS

The economic operational needs assessment will be performed prior to the benchmarking milestone. SPP will classify flowgates meeting either of the following criteria as economic needs:

1. The flowgate was 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, or
2. The flowgate had congestion costs[38] totaling more than $10 million over the previous 24 months excluding the effects of prior outage conditions, or
3. The flowgate had congestion costs[39] totaling more than $50 million over the previous 24 months including the effects of prior outage conditions.

Congestion cost for outages will be provided for informational purposes.

SPP also will identify economic needs considering manual commitments of uneconomic generation for local area voltage support, according to either of the following criteria:

1. Manual commitment events that include startup and extension 25 percent of the year, or
2. Manual commitments that do not exceed 25 percent of the year, but cost over $1 million dollars over 24 months.

4.4.2 RELIABILITY OPERATIONAL NEEDS

SPP also will identify facilities as reliability needs due to system reconfiguration using agreed upon (by SPP and the transmission operator) operating guides or operating instructions if they meet the following criteria:

1. High- or low-voltage issues where system reconfiguration is implemented[40] 10 percent of the year due to non-outage issues[41], or
2. Thermal loading issues where system reconfiguration through the use of an agreed upon operating guide has been implemented[42] in real-time 25 percent of the year.

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[38] Congestion costs will be calculated using the same methodology as the SPP violation relaxation limit process.
[39] Congestion costs will be calculated using the same methodology as the SPP violation relaxation limit process.
[40] "Implemented" shall mean the reconfiguration is in effect on the real-time system during periods of time where pre-contingent or calculated post-contingent SOL exceedances would have occurred.
[41] 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 one percent of the time.
[42] "Implemented" shall mean the reconfiguration is in effect on the real-time system during periods of time where pre-contingent or calculated post-contingent SOL exceedances would have occurred.

SPP will identify facilities as reliability needs due to pre-contingency or calculated post-contingency System Operating Limit (SOL) exceedances[43] that have occurred in real-time operations if they meet the following criteria:

1. The total pre-contingency or calculated post-contingency thermal SOL exceedances, calculated as total cumulative minutes, over the previous 24 months exceeded 4 days, or
2. The total pre-contingency or calculated post-contingency voltage exceedances, calculated as total cumulative minutes, over the previous 24 months exceeded 4 days.

[43] Pre-contingency and calculated post-contingency SOL exceedances are determined through coordination between the Transmission Owner, Transmission Operator, and SPP Reliability Coordinator and are based on their Real-Time Assessments in accordance with the applicable SPP FAC-011 methodology(ies) and the applicable Transmission Owner FAC-008 methodology(ies).

5 SOLUTION DEVELOPMENT AND EVALUATION

5.1 DETAILED PROJECT PROPOSAL PROCESS

Pursuant to the SPP tariff and SPP business practices, SPP will open a 30-day detailed project proposal (DPP) transmission planning response window in which SPP stakeholders can submit solutions to system needs identified during the needs assessment. Solutions submitted outside the DPP window may also be considered in solution development and evaluation. Solutions to the posted needs may include transmission solutions, model adjustments, operating guides, and non-transmission solutions.

5.1.1 SOLUTIONS

During the DPP window, all DPP submittals must be submitted through SPP's RMS for tracking purposes using the most current DPP submittal form, located on the SPP website. This allows SPP to track the submission as well as communicate with the individual project submitter. SPP will develop solutions to the needs posted in the needs assessment in accordance with the project schedule.

5.1.1.1 Transmission Projects

Transmission projects require new, rebuilt, upgraded, or replacement facilities.

5.1.1.2 Storage as Transmission-Only Asset (SATOA)

Transmission expansion may include any facilities that are eligible to be included in the transmission system as provided for under the SPP tariff, including SATOA. Any SATOA may only inject and withdraw energy in the Energy and Operating Reserve Markets to the extent necessary to receive energy from the transmission system and to inject energy into the transmission system to provide the services for which the SATOA was issued an NTC.

Operation of SATOA in real-time will be under the functional control of the Transmission Provider (TP). For each SATOA included in the ITP, the TP in conjunction with the transmission operator will develop an operating guide specifying the operating practices applicable to the SATOA and consistent with the system performance requirements determined through the planning study supporting the selection of the SATOA for inclusion in the ITP. The operating guide will include limitations on the operation of the SATOA above the maximum capacity determined to be needed to address the need. The operating guides will also address any scenario when a SATOA might be utilized under emergency conditions to relieve a system condition that it was not explicitly issued to address. SATOAs will be considered for this usage after routine congestion management has been tried, but before load shedding.

Commented [sam2]: RR476 Storage as a Transmission-Only Asset:
-Approved by MOPC: 1/10/2022
-Posted with FERC: 7/12/2022 (pending)
- FERC Docket #ER22-2344

-Requested FERC Effective Date: TBD

Notes: Requested order by October 11, 2022 to allow SPP to develop, test, and move the proposed revisions into the production phase of SPP's software systems. Actual effective date of the language was left as unknown with an expected implementation date to be in 2025.
11-02-2022: FERC requested additional information with the due date of 12-02-2022. SPP filed deficiency response on 12-02-2022.

Commented [SP3R2]: FERC has accepted the filing as of 5/26/2023; however, no effective date has been granted by FERC, so this language is still pending.

5.1.1.3 Non-Transmission Solutions

Non-transmission solutions are generally considered technologies and methods that can complement the transmission grid in a predictable way, and provide certainties required for planning purposes. Flexible AC Transmission Systems (FACTS) and Power Flow Controllers (PFC) are examples of technologies that can be used as non-transmission solutions, and Dynamic Line Rating technologies are examples of technologies that do not meet this definition. As provided for under Attachment O, Section III.7.c., storage facilities that are not proposed as SATOA may be considered as alternatives to transmission assets to address system needs when participating as generation or demand-side resources.

Commented [sam4]: RR476 Storage as a Transmission-Only Asset:
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11-02-2022: FERC requested additional information with the due date of 12-02-2022. SPP filed deficiency response on 12-02-2022.

Commented [SP5R4]: FERC has accepted the filing as of 5/26/2023; however, no effective date has been granted by FERC, so this language is still pending.

5.1.1.4 Model Adjustments

In the instance that a need is included in the needs assessment due to incorrect or outdated information included in any of the models, SPP stakeholders are encouraged to submit appropriate model adjustments to mitigate the issue.

5.1.1.5 Operating Guides & Planning Guides

The section defines how and when a transmission operating guide (TOG) is modeled in ITP models and has no effect upon how operating guides are implemented in real-time. In most cases, TOGs are not intended to indefinitely defer needed transmission upgrades.

SPP shall maintain a list of TOGs submitted by the respective TOs that should be considered for use in ITP assessments. This list will be reviewed annually as part of the SPP annual data request and any necessary changes, additions, or withdrawals will be made at that time. An effective TOG shall continue to be considered in ITP assessments unless and until the facility-owning TO or transmission operator withdraws the TOG.

For a TOG to be considered for use in the ITP as a possible mitigation plan, it shall be included in the TO's submitted list of TOGs. An effective TOG must state the system conditions under which the TOG is to be used and describe, in detail, the action the operators will take. TOs must provide sufficient modeling data to simulate the operators' actions. The TO and transmission operator shall coordinate on the TOG, including documentations on why it is a current mitigation plan. The TOG must be approved by someone in charge of operations from the TO or transmission operator submitting the TOG, as well SPP Operations staff.

In the case of TOGs affecting facilities owned by multiple parties, the affected parties must coordinate on the addition or removal of any TOG from the planning process. The entities shall agree on the inclusion or removal of an effective TOG from the ITP assessment.

A TOG can be considered an effective solution for facilities that are not listed in the TOG if in the act of implementing the TOG for the elements listed, other overloads or voltage violations are corrected, with the consent of the impacted TOs in coordination with the transmission operators.

5.1.1.5.1 Additional TOG Requirements

1. A TOG requiring generation redispatch must indicate if generator location is critical and, if so, must state in detail which units or plants will be redispatched. Absence of such data indicates location is not critical and generators may be selected from the fleet the entity has authority to run. The ramp rate of the generation must be capable of relieving the overload or voltage issue within the time allowed as specified in the TOG. The modeling data files must also redispatch other generation to make up for any and all energy deficits introduced by the TOG's change in dispatch.
2. A TOG must not cause a violation elsewhere on the transmission system.
3. A TOG must be executable within the time duration applicable to the facility ratings.
4. TOGs meant for dynamic stability will not be considered for steady-state conditions.

5. A TOG shall include the means by which system control is implemented (i.e., manual or supervisory control).

5.1.2 SPP DEVELOPED SOLUTIONS

In addition to solutions submitted by SPP stakeholders through the DPP process, SPP may develop solutions internally to mitigate needs.

5.2 COST ESTIMATES

The cost estimates used for projects tested in the initial project development phase will be conceptual estimates as described in SPP business practices. The conceptual estimates will be developed by SPP and will utilize standardized estimates and multipliers that are based on historical data. Study estimates may be determined for projects during the initial project development if historical data is limited or unavailable.

The draft portfolio and high performing projects as determined by SPP that pass the initial screening phase, detailed in the Portfolio Development section of this manual, will be designated for study estimates as described in business practices. The study estimates will provide a more refined cost estimate for potential project approval. Prior to the solution development phase, SPP will make a preliminary determination of any proposed upgrades that are potentially competitive according to Attachment Y, Section I, for the limited purpose of determining the appropriate party to prepare the study estimate. SPP, or a designated third party, will prepare study estimates for potentially competitive upgrades. Incumbent TO(s) will prepare study estimates for potentially non-competitive upgrades. All study estimates will utilize the standardized cost estimate reporting template (SCERT) for all upgrades that are required to complete that project.

5.3 SOLUTION EVALUATION PROCESS

5.3.1 ECONOMIC SOLUTION EVALUATION

All solutions[44] will be evaluated based on their one-year benefit-to-cost ratio (B/C) and 40-year net present value (NPV) B/C, using conceptual cost estimates. If a solution mitigates congestion for an economic need and has at least a 0.5 one-year B/C or a 1.0 40-year NPV B/C, it will be included for further consideration during portfolio development. For the 40-year NPV B/C, the average SPP net plant carrying charge and an in-service date of year 5 will be applied.

Potential seams projects will be identified and flagged as such if they meet either of the following criteria:

- Interconnects SPP with a non-SPP TO.
- Adjusted production cost benefit to a neighboring entity is at least 20 percent of total benefit of SPP and the neighboring entity.

When flagged as a potential seams project, SPP will apply a minimum of 20 percent of the total project cost to the applicable neighboring entity. SPP will work to determine what level of cost-sharing will make it viable for the SPP entity and whether or not there is an opportunity for cost-

[44] Regardless of the type of need the solution was submitted to address

sharing with a neighboring entity. SPP will work with the appropriate neighboring entity to evaluate any potential seams projects and determine if there is a willingness to proceed jointly.

5.3.2 RELIABILITY SOLUTION EVALUATION

All solutions[45] will be evaluated against reliability needs. SPP will use the following metrics to evaluate potential benefits-to-proposed cost:[46]

- Cost per loading relief (CLR[46])– relates the cost of a proposed solution to the amount of thermal loading relief for a need
- Cost per voltage relief (CVR[46]) – relates the cost of a proposed solution to the amount of voltage support relief for a need

The CLR and CVR metrics will be calculated for every solution against each need it mitigates. Solutions that change the status of a unit requested to be offline due to seasonal availability (not outage related), may be used to mitigate violations identified as a result of the resource being made available. The metric calculations will provide a ranking of the solutions for each need. SPP will use the metrics as a tool during project selection for the reliability portfolio development.

Potential seams projects will be identified and flagged as such if they meet either of the following criteria:

- Interconnects SPP with a non-SPP TO.
- Addresses an identified first-tier potential reliability issue.

SPP will determine what level of cost-sharing of any potential seams project would make it viable for the SPP region and whether or not there is an opportunity for cost-sharing with a neighboring entity. SPP will work with the appropriate neighboring entity to evaluate any potential seams projects and determine if there is a willingness to proceed jointly.

Solutions involving storage as a transmission asset will be evaluated using additional criteria to reflect their unique characteristics. These additional criteria could include but are not limited to:

1. Ability of the proposed SATOA to address transmission need (e.g., loading, voltage, stability, congestion) in the hours that the need is determined to exist,
2. Assurance of sufficient Energy and/or reactive capability (MWh/MVAr) to charge or discharge Energy for any period identified as necessary in the planning study.
3. Assessment of system reliability impacts applicable to inverter-based facilities on the same basis and in a manner comparable to such analysis in the Generator Interconnection Procedures applicable to storage Resources as inverter-based facilities.
4. Life-cycle cost comparisons, including consideration of the period that is required to address the transmission need, which may be different than the life cycle of alternatives.
5. Additional qualitative considerations that may support comparative evaluation to other solutions to the need(s), such as lead time to develop, right of way, expandability, and operational flexibility.

[45] Regardless of the type of need the solution was submitted to address
[46] Relief score calculations can be found in the reliability metrics document approved by the TWG

Commented [SP6]: RR476 Storage as a Transmission-Only Asset:
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11-02-2022: FERC requested additional information with the due date of 12-02-2022. SPP filed deficiency response on 12-02-2022.

Commented [SP7R6]: FERC has approved language as of 5/26/2023; however, no effective date has been granted by FERC, so this language is still pending.

5.3.3 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.

5.3.4 PERSISTENT OPERATIONAL SOLUTION EVALUATIONS

A subset of solutions will be evaluated to address persistent operational needs utilizing the filtering criteria, as approved by the TWG, ESWG and ORWG. Reliability solutions will be evaluated by the CLR and CVR metrics described in the Reliability Solution Evaluation section. SPP will track congested economic operational needs against needs identified in the current ITP, identify differences between real-time market operations and planning models, and determine the need for and impact of planning model adjustments and analysis. SPP will make a recommendation to applicable stakeholder working groups on how to address unresolved reliability or economic operational needs. Recommendations may include, but are not limited to, transmission upgrades, operational mitigations, or additional analysis to be performed in a future ITP study.

5.3.5 ZONAL PLANNING CRITERIA SOLUTION EVALUATION

The solutions submitted along with the ZPC exceedances will be evaluated in accordance with this Reliability Solution Evaluation section. A subset of solutions may be provided to the local TO to evaluate against the ZPC exceedances during the solution development phase of the ITP assessment. TOs will notify SPP of solutions that mitigate any of their ZPC exceedances. Solutions that mitigate ZPC exceedances will be considered for project displacement during portfolio development.

6 PORTFOLIO DEVELOPMENT

6.1 PORTFOLIO DEVELOPMENT METHODOLOGIES

Portfolios will be developed for each need type and evaluated for synergies as described in this section. SPP will consider stakeholder feedback when selecting a portfolio for each future. Specific solutions and the reasoning for inclusion or exclusion in the draft or final portfolios will be available for discussion at the planning summit or other open SPP stakeholder forums such as working group meetings.

In developing the draft or final portfolios, consideration of the following information may be given to the top-ranking solutions, as applicable. It must be noted that these considerations may result in changes in top-ranking solutions, including the elimination of solutions:

1. One-year project cost, APC benefit, and B/C.
2. 40-year NPV cost, APC benefit, and B/C.
3. Congestion relief that a project provides for the economic needs of that future and year.
4. Project overlap, or when two or more projects that relieve the same congestion are in a single portfolio.
5. The potential for a project to mitigate multiple economic needs.
6. Any potential routing or environmental concerns with projects.
7. Any long-term concerns about the viability of projects.
8. Seam and non-seam project overlap.
9. Relief of downstream and/or upstream issues, tested by event file modification.
10. The potential for a project to mitigate reliability, operational, and public policy needs, which covers current market congestion.
11. The potential for a project to address non-thermal issues.
12. The need for new infrastructure versus leveraging existing infrastructure.
13. Larger-scale solutions that provide more robustness and additional qualitative benefits.
14. Replacement, rebuild or upgrade of the aging infrastructure to address the longer-term economic, reliability and/or resiliency needs of the grid.

6.1.1 ECONOMIC PORTFOLIO DEVELOPMENT

Solutions mitigating economic needs are ranked by their cost effectiveness, net APC benefit and qualitative benefits for each need or set of needs and categorized into one or more of the following groupings:

- Cost effective: Solutions with the lowest cost with respect to the congestion relief they provide on individual flowgates will be selected.
- Highest net APC benefit: Solutions with the highest difference between one-year APC benefit and one-year project cost will be selected.
- Multi-variable: Top-ranking projects in the other two groupings, as well as qualitative benefits that the other groupings may not capture, will be considered when selecting projects.

Study estimates for the top-ranking projects from each economic grouping will be developed consistent with the Cost Estimates section of this manual. Once study estimates are applied to the top-ranking solutions in each grouping, the limited set of solutions will be ranked again to reflect the cost refinement.

The top-ranking economic projects will be tested in a new set of base models that include the corresponding reliability, policy, and operational economic portfolios. The economic projects will be tested individually within each group to assure only those with at least a 0.9 one-year B/C or 1.0 40-year NPV B/C move forward.

6.1.2 RELIABILITY PORTFOLIO DEVELOPMENT

Solutions mitigating reliability needs will be ranked and displaced according to the reliability metrics, then assessed from a qualitative standpoint. SPP will review this draft portfolio of solutions to determine if a better overall project can be selected from a qualitative standpoint. After SPP has reviewed the draft portfolio, study estimates for the top-ranking projects from the reliability grouping will be developed consistent with the Cost Estimates section. Additional study estimates may be developed if a project performs well according to reliability metrics or is considered a high-performing project from a qualitative standpoint. When study estimates are developed, the reliability metrics are recalculated with the refined cost estimates and the portfolio is updated to consider the impact of SPP stakeholder feedback or solutions that have higher or lower costs than originally estimated. Additional study estimates may be developed until the final reliability portfolio is determined for each future.

6.1.3 PUBLIC POLICY PORTFOLIO DEVELOPMENT

Solutions mitigating public policy needs 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 and tested individually within the policy grouping to ensure there is no redundancy of need mitigation within the set of projects.

6.1.4 PERSISTENT OPERATIONAL PORTFOLIO DEVELOPMENT

Solutions mitigating persistent operational needs are ranked by the appropriate metrics depending on whether the need is economic or reliability based. Solutions identified to mitigate persistent operational issues will be compared with the other portfolios to ensure efficiencies are gained by identifying the most cost effective projects to meet all needs. Economic solutions will be ranked based on their project cost compared to the cost incurred without the project. SPP and stakeholders will determine the criteria for development of the operational portfolio, which will be included in each study scope. Reliability solutions will be evaluated using the CLR and CVR metric concept.

6.1.5 PORTFOLIO SYNERGY

After the economic, reliability, operational, 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.

6.2 PORTFOLIO CONSOLIDATION

To determine a recommended plan, the portfolios of potential projects must be consolidated. SPP and stakeholders will discuss, determine and document details of the study-specific consolidation criteria during each study scope development.

6.3 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 2, 5, 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 conflict with staging results for methods described in this section. In these instances, SPP will consider these step changes within the model set to inform need date recommendations. During project staging, SPP will also consider future assumptions, current market conditions, and other available transmission system information.

If any projects with existing NTCs show an earlier need date than the need date on the NTC letter, SPP may recommend acceleration of the project.

Staging for each type of project is described in the following three sections. Staging for persistent operational projects are included in the economic and reliability project sections.

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

6.3.1 ECONOMIC PROJECTS

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

Other economic projects in the final consolidated portfolio will be staged in the first year 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 5 and year 10, based on linear interpolation of B/C ratios between the year 5 and year 10 models. Figure 4 represents the linear interpolation of B/C ratios of an upgrade. In this example, if year 5 is 2020 and year 10 is 2025, the need date would be 2024.

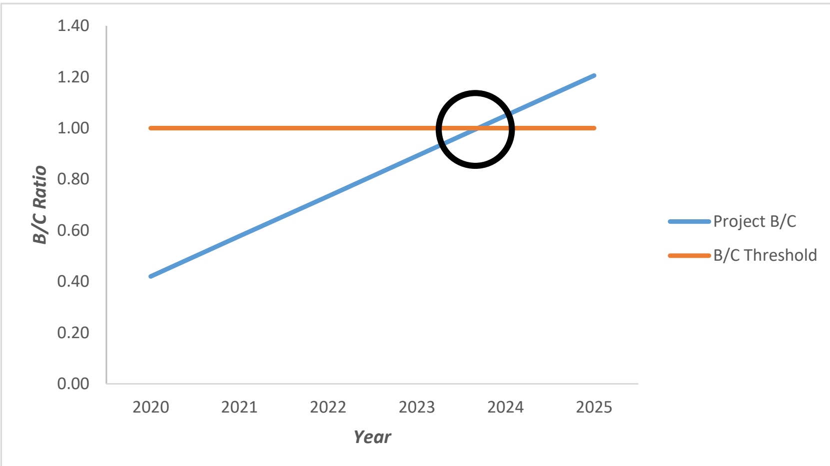

Figure 4: Economic Project Staging Example

6.3.2 RELIABILITY PROJECTS

Projects 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.

Reliability projects in the final consolidated portfolio will be staged based on the year and season when the needs addressed by each project appear on the transmission system. All upgrades that solve year 2 violations will be initially staged for an in-service date in the corresponding season in which the violation occurs for year 2.

For upgrades that solve reliability needs in year 5 and year 10, the 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's model on record. For example, a violation that occurs in year 5 summer peak will be staged between the summer peaks of year 2 and year 5, based on the results of linear interpolation between the year 2 and year 5 summer-peak models.

Figure 5 represents the linear interpolation for thermal loading on a transmission line. In this example, if year 2 is 2021 and year 5 is 2024, the need date would be June 1, 2024.

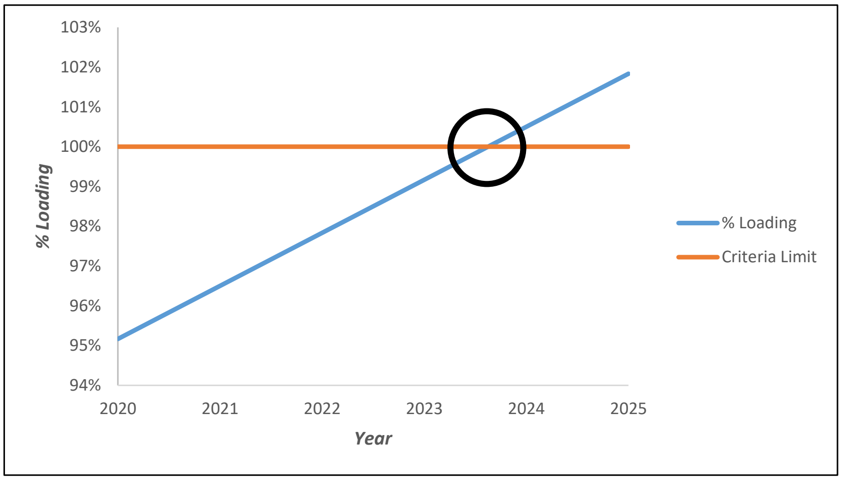

Figure 5: Reliability Project Staging Example

6.3.3 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 5 and year 10, based on linear interpolation of progress towards mitigating the public policy need between the year 5 and year 10 models. Figure 6 represents the linear interpolation of progress towards resolving a public policy need. In this example, if year 5 is 2020 and year 10 is 2025, the need date would be 2024.

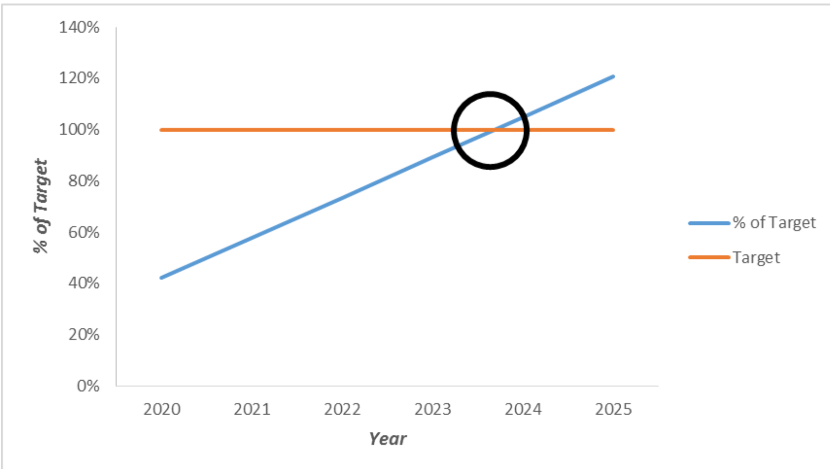

Figure 6: Public Policy Project Staging Example

6.4 FINAL RELIABILITY ASSESSMENT

To evaluate and confirm the effectiveness of all identified upgrades for the recommended portfolio, a final reliability assessment will be performed. The base reliability and Market Powerflow models will be modified to include the recommended portfolio and model adjustments identified during solution development, regardless of project classification. A contingency analysis will be performed to identify any new reliability violations on this updated set of powerflow models.

If any new reliability violations are observed in the modified base reliability models, the recommended portfolio may be modified with a new or modified solution. The final portfolio will include the changes determined from the incremental reliability assessments.

If any new reliability violations are observed in the modified Market Powerflow models, they will be documented in the ITP assessment report: however, no solutions will be developed. SPP will perform a spot check contingency analysis on economic solutions. This analysis will be used to determine the effect of potential dispatch changes as constraints are removed or adjusted due to the solutions and ensure that those changes do not result in additional reliability violations.

The analyses described in this section will begin as SPP develop draft portfolios to identify projects that may have adverse impacts to the transmission system as quickly as possible.

The results of the final reliability assessment on the recommended portfolio will be documented in the ITP assessment report. Any upgrades added to the recommended portfolio as a result of the final reliability assessment will be identified.

7 INFORMATIONAL PORTFOLIO ANALYSIS

7.1 BENEFIT METRICS

Benefit metrics will be used to measure the value and economic impacts of the final consolidated portfolio to be expected from the ITP assessment. 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 the metrics in Table 6, refer to the Benefit Metrics Manual.[47]

ITP Assessment 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

Table 6: ITP Assessment Benefit Metrics

7.2 SENSITIVITY ANALYSIS

Sensitivity analyses will be defined in the scope and conducted to measure the flexibility of the final portfolio in each ITP assessment. Generally, these sensitivities will not be used to select the proposed transmission projects, nor to filter out projects. Sensitivities may consider variations in demand, fuel prices, renewable energy, or other relevant considerations as determined during futures development.

[47] Benefit Metrics Manual

8 DELIVERABLES

8.1 FINAL REPORT

The deliverable for each ITP assessment will be a report detailing the analysis, results, and recommendations for a cost-effective and robust portfolio(s) that takes into account the likelihood of the future(s) studied. In addition to analysis details and results, a SPP recommended transmission plan for the Board to consider for approval will be included in the final report.

Parts of each ITP study report will be incorporated into the annual SPP Transmission Expansion Plan (STEP) report.

9 ISSUANCE OF NTCS

When projects are approved by the Board, SPP will issue NTCs in accordance with the SPP tariff and SPP business practices.

10 SPP AND STAKEHOLDER ACCOUNTABILITY

SPP and stakeholders will introduce steps to focus on accountability for timelines and milestones that consist of mechanisms designed to promote the timely exchanges of data, reviews, and approvals within the transmission planning process.

10.1 PROJECT SCHEDULE

SPP will develop a project schedule in parallel with the development of the scope of each successive study. This schedule will identify the timing, duration, and responsible parties for all data exchanges, reviews, and approvals required to complete the ITP assessment. SPP will coordinate with SPP stakeholders in the development of this schedule and formally vet the final schedule with SPP stakeholders upon the completion of the study scope.

This schedule will be maintained by SPP and regularly reviewed at appropriate SPP stakeholder meetings to keep affected parties informed of upcoming milestones to ensure the timely completion of the planning process.

10.2 POINT OF CONTACT

Clear and timely two-way communication between SPP and stakeholders is vital to the successful completion of the annual study process and the use of a central point of contact (CPOC) will increase the coordination and timely delivery of information necessary to meet scheduled milestones.

Using the project schedule described in this section, SPP stakeholders will appoint a CPOC to work with SPP to coordinate the timely flow of information. Once provided to SPP, a list of SPP stakeholder contacts will be developed and posted on SPP's secure website, viewable to those with access to the website[48] and corresponding ITP assessment folder.

SPP stakeholders have flexibility when identifying the CPOC for their respective companies, which include:

- Identifying a specific person who will coordinate the various requests that come out of the planning process.
- Assigning individuals who will be responsible for specific parts of the planning process. For example, identifying a CPOC who will be responsible for coordinating the submission of all data required to support the modeling and planning processes. Another individual may be responsible for project review and cost-estimate submittals.
- Providing SPP with an email address to be used for requests that will target specific groups with their organization instead of naming an individual. For example, modeling@abcinc.com can be used to target the entire modeling team. Email addresses can be provided for company groups that will be responsible for the various parts of the planning process.

[48] Access to the website can be requested through SPP RMS

10.3 LATE DATA AND PROCESS WAIVER

10.3.1 LATE DATA

Data Owners[49] are responsible for providing the data necessary to model their assets to SPP. All required data must be received by SPP and reviewed by Data Submitters per the specific deadlines and milestones listed in the ITP schedule[50] for model development. The schedule will be provided to all stakeholders and posted on the SPP website. If the applicable deadlines are not met, SPP will use the most appropriate modeling data on file as proxy data. Typically, this will be the most recently submitted data. Failure to perform the required reviews in a timely manner should not cause a delay in the corresponding process. In the event review deadlines are missed, the items requiring review or approval will be used as is and the process will move forward without delay.

Late data updates to the ITP models can cause major impacts to the ITP schedule and overlapping model development timelines for various SPP planning assessments. The ITP assessment satisfies a portion of SPP's NERC TPL-001 compliance requirements, which are required to be completed on an annual basis. ITP study milestone completion is dependent on a timely model build. Additionally, timely delivery of ITP models is necessary in various tariff services assessment processes and committed timelines, including SPP processes such as Delivery Point Addition, Transmission Services, and Generator Interconnection.

10.3.2 LATE DATA SUBMISSION AND APPROVAL PROCESS

Data submitted after the applicable deadlines for milestones listed in the ITP schedule for model development will require a late data submission form sent via RMS. If a specific data submission requires the use of a separate process, software, or other applicable tools, the submitting entity shall provide evidence of that data submission being provided through the separate process, software, or other applicable tool at the same time as the late data submission form. SPP will not consider a request to incorporate late data prior to submission of the late data submission form and receipt of the relevant late data. The submitting entity will be required to explain why the data is late and the estimated benefits of adding the late data to the applicable models. SPP will have up to ten (10) business days after receiving the late data submission form to develop the estimated impacts to the scope, schedule, and costs of accepting the late data and communicate the late data submission form, with SPP's estimated impacts to the scope, schedule, and costs of accepting the late data to the ESWG and TWG members. In situations where there are no material impacts to the scope, schedule, or cost, SPP staff will notify TWG and ESWG members of the changes as "information only" but will not require any approvals unless a TWG or ESWG member requests a vote. In situations where the late data does have a material impact to scope, schedule, cost, or a member call for a vote, then SPP staff will communicate via email that the late data will be discussed at the next regularly scheduled working group meeting for approval or rejection. SPP may request an out-of-schedule meeting to review and vote on a waiver request. If approved by either the TWG or ESWG and there are no adverse impacts to the study process, schedule or costs, then the data change will be applied to the applicable ITP models. If approved by either the TWG or ESWG and there are expected adverse impacts to the study process, schedule or costs, then the

[49] From the SPP Model Development Procedure Manual, Data Owner is defined as "The entity that is responsible for ensuring the accuracy and timely submission of data to the SPP, as Planning Coordinator, in accordance with the SPP Model Development Procedure Manual."

[50] Coordination amongst the TWG, ESWG, and MDAG will be necessary as it relates to the model development schedules for the SPP planning processes

applicable working group will seek approval of a process waiver per section 10.3.3. If rejected by both the TWG and ESWG, the data changes will not be applied to the ITP models. Data that was submitted on time but was missed or was applied incorrectly will be incorporated without the late data submission form or approvals to the necessary models unless there is a significant impact to the ITP schedule. SPP staff will inform the appropriate working groups at the next scheduled meeting(s) of the situation and request, if necessary, approval or rejection of the change.

10.3.3 PROCESS WAIVER

SPP or an applicable working group may request a waiver if a process issue causes an expected adverse impact to the study results, process, schedule, or costs. SPP will assess the issue and provide feedback to the appropriate working group(s) for consideration of a waiver as necessary and determined by SPP. If applicable, upon a working group recommendation, SPP may move forward with a waiver request.

An entity or SPP may solicit MOPC for a delay in the posting of the final study report or for the approval of additional effort that would require unbudgeted dollars to augment or provide additional support for SPP to meet study schedule milestones to meet the posting date of the final study report. The waiver request should include background information on the issue and the rationale for requesting the delay or the need for unbudgeted dollars to support staff efforts. In support of the waiver process, SPP will provide MOPC with the project schedule impacts, schedule mitigation plans and an estimate of any costs associated with accommodating the waiver to support MOPC's decision-making process.

SPP may request that MOPC conduct an email vote or out-of-schedule meeting to review and vote on a waiver request.

10.4 MOPC REPORT

SPP will provide a quarterly report to MOPC highlighting the assessment milestones from the preceding quarter. Updates will be given on adherence to milestone timelines in regard to data review and submittal, scheduled reviews and approvals, and on issues that may have required mitigation for the process to remain on schedule.

A summary of the participation of SPP and stakeholders will inform MOPC of the importance of the successful completion of milestones and adherence to deadlines critical to produce a complete, high quality, and timely report and portfolio. Issues requiring mitigation, as mentioned previously in this section, whether through the actions of SPP or stakeholders will be presented in sufficient detail to give MOPC a clear picture of the issue and remedies put in place to avoid potential impacts to the process schedule.

11 APPENDICES

11.1 HISTORY OF THE ITP ASSESSMENT

In January 2009, the SPP Board of Directors (Board) 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 assessment, develop a plan to monitor the construction of projects approved through the ITP assessment, 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 the Regional State Committee (RSC) establish a "highway/byway" cost allocation methodology for approved projects.[51]

The SPPT developed an integrated set of principles that should guide SPP in the development of its comprehensive ITP assessment:

1. SPP's primary function is to "keep the lights on," and one way that is accomplished is to provide transmission service for customers within the SPP region. In order to meet this long-term function, SPP must plan for and construct a robust transmission system. This robust transmission system should be large in both scale and geography so as to provide flexibility to meet SPP's future needs.

2. SPP's planning process for a robust transmission system must consider transmission as an enabler to meet short-term and long-term needs. Planning of SPP's transmission system must take into consideration the anticipated location of future generation facilities and should incorporate various scenarios regarding load growth, demand response, energy efficiency, fuel prices, environmental and governmental regulations and policies, and other factors.

3. SPP's planning processes should take a long-term view (20 or more years) of the benefits and costs of all projects while also expediting priority system investments.

4. As a priority, through the RSC and the membership, SPP should resolve the uncertainties associated with financing transmission projects by establishing the appropriate regional cost allocation methodologies. This effort should result in a reduction of the number of cost allocation mechanisms that exist today. SPP members, customers, and interested parties must participate in this effort with their regulators to establish the appropriate cost recovery methods.

5. Once SPP has developed and obtained the approval of a robust transmission plan for the region, the BOD and RSC should ensure that construction is commenced and completed according to an established timeline.

SPP began performing its planning duties in accordance with the ITP assessment in July 2010.

[51] The Highway/Byway methodology was approved by FERC on June 17, 2010.

11.2 THE TRANSMISSION PLANNING IMPROVEMENT TASK FORCE

In February 2015, the Transmission Planning Improvement Task Force (TPITF) was assembled by the 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 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-year, and 20-year assessments), SPP assessments for compliance with NERC TPL standards 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; 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.

The TPITF recommendation whitepaper[52], was 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 recommendation 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 developed five recommendations to accomplish this scope of work that are discussed in detail throughout this manual:

1. Replace the current ITP schedules with an annual transmission expansion plan.
2. Create a standardized scope.[53]
3. Establish a common planning model for use across the various SPP planning processes.
4. Utilize a holistic planning process.
5. Create SPP staff/stakeholder accountability process for the timely exchanges of data, reviews and approvals.

11.3 ACRONYMS

Acronym	Term
AECI	Associated Electric Cooperative, Inc.
APC	Adjusted Production Cost
B/C	Benefit-to-Cost Ratio
BA	Balancing Authority
CLR	Cost per Loading Relief
CPOC	Central Point of Contact
CVR	Cost per Voltage Relief
DISIS	Definitive Interconnection System Impact Study
DPP	Detailed Project Proposal
EHV	Extra High Voltage
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
ESWG	[SPP] Economic Studies Working Group
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operation & Maintenance [Costs]
GIA	Generator Interconnection Agreement
GIS	Geographical Information System
IFTS	Interruption of Firm Transmission Service
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
ITP	Integrated Transmission Planning
ITPNT	ITP Near-Term Assessment
ITP10	ITP 10-Year Assessment
LMP	Locational Marginal Price
LPC	Local Planning Criteria
MDWG	[SPP] Model Development Working Group
MISO	Midcontinent Independent Transmission System Operator, Inc.
MMWG	[ERAG] Multiregional Modeling Working Group
MOPC	[SPP] Markets and Operations Policy Committee
MW	Megawatt
MWh	Megawatt-Hour

Acronym	Term
NCLL	Non-Consequential Load Loss
NERC	North American Electric Reliability Corporation
NERC TPL	NERC Transmission Planning Standards
NPV	Net Present Value
NTC	Notification to Construct
NTC-C	Notification to Construct with Conditions
OATT	Open Access Transmission Tariff
ORWG	[SPP] Operating Reliability Working Group
PPA	Power Purchase Agreement
PST	Phase-Shifting Transformer
PTC	Production Tax Credit
RFP	Request for Proposal
RMS	[SPP] Request Management System
RPS	Renewable Policy Standard
RR	Revision Request
RSC	Regional State Committee
SCED	Security-Constrained Economic Dispatch
SCERT	Standardized Cost Estimate Reporting Template
SCUC	Security-Constrained Unit Commitment
SERC	SERC Reliability Corporation
SPC	[SPP] Strategic Planning Committee
SPP	Southwest Power Pool, Inc.
SPPT	Synergistic Planning Project Team
SSC	[SPP] Seams Steering Committee
STEP	SPP Transmission Expansion Plan
TDF	Transmission Distribution Factor
TO	Transmission Owner
TPITF	[SPP] Transmission Planning Improvement Task Force
TWG	[SPP] Transmission Working Group
VOM	Variable Operation & Maintenance [Costs]
WECC	Western Electricity Coordinating Council

11.4 DEFINITIONS

1. Market Economic Models – model set containing all economic parameters and powerflow data necessary to perform SCUC/SCED simulations
2. Market Powerflow Models – model set containing all powerflow data, including load and generation dispatch from the SCUC/SCED simulations
3. Base Reliability Models – model set representative of how load responsible entities within SPP would serve load utilizing only resources with long-term firm transmission service
4. Balancing Authority – an entity responsible for maintaining a load, generation, and interchange balance within its region
5. Congestion Score – the product of a constraint's annual average shadow price and the number hours the constraint binds; value used to rank economic needs by severity and/or longevity
6. Detailed Project Proposal – a submittal form in which stakeholders may submit solutions to solve ITP needs
7. First-Tier – The non-SPP transmission system that is electrically interconnected to the SPP transmission system and extends throughout the interconnected entity's footprint
8. Grouping – specific to economic portfolio development; set of projects that are selected by economic characteristics (cost-effectiveness, net APC benefit, etc.) from initial screening runs and meet a 0.9 one-year B/C or 1.0 40-year B/C within the set of projects
9. Light Load Model – model representative of each submitting entity's one-hour system minimum load between April and May, non-coincident to the SPP system
10. Manual Commitments - a commitment of a resource outside of the automated market process to alleviate constraints
11. Net Plant Carrying Charge - annual percentage that is applied to a utility's depreciated plant costs to calculate an annual revenue requirement billed on Schedule 11 of the SPP Tariff; calculated by a transmission owner's revenue requirement divided by the net transmission plant investment.
12. Notification to Construct: A written notice from SPP directing an entity that has been selected to construct one or more transmission project(s) to begin or continue implementation of the transmission project(s) in accordance with Attachment Y of the SPP Tariff.
13. SPP Open Access Transmission Tariff: SPP governing document filed for compliance with FERC Order 888
14. Reference-Case Future – one future (of up to three) that will be included in each ITP assessment; reflective of a future scenario in which there are no major policy changes
15. Revision Request – an SPP mechanism by which SPP governing documents can be revised through the stakeholder process
16. Seams – areas of or near the boundary of the SPP footprint that are directly impacted by the operation of SPP and non-SPP systems
17. Shadow Price – the potential reduction in total production costs if the limit on a congested flowgate were to be increased by 1 MW
18. State Estimator – a standard industry tool that produces a powerflow model based on available real-time metering information; information regarding the current status of lines, generators, transformers, and other equipment; bus load distribution factors; and a representation of the electric network to provide a complete description of system conditions, including conditions at buses for which real-time information is unavailable.
19. SPP Transmission Expansion Plan – The plan that describes the transmission expansion projects being considered over the planning period and developed through the stakeholder process in accordance with the SPP Tariff and approved by the SPP Board.

20. Study Scope – document specific to each individual ITP assessment to be developed by SPP staff and stakeholders containing study assumptions to be utilized that are not included in the ITP Manual
21. Summer Peak Model – model representative of each submitting entity's one-hour system peak load between June and September, non-coincident to the SPP system
22. Winter Peak Model – model representative of each submitting entity's one-hour system peak load between December and March, non-coincident to the SPP system