2026 INTEGRATED TRANSMISSION PLANNING & CPP TRANSITION ASSESSMENT SCOPE

By SPP Engineering

Published on 07/02/2025

Version 1.2

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
11/26/2024 v0.1	SPP Staff	Initial draft	
12/04/2024 v0.2	SPP Staff	Updated draft; section 2 modified	For CPPTF, ESWG and TWG review at December meetings
12/11/2024 v0.3	SPP Staff	Updated draft; sections 1 Overview & 3 Models modified; Section 2 SCR moved	Updated per comments during CPPTF meeting on 12/6/2024 and Joint ESWG-TWG meeting on 12/11/2024
12/20/2024 v0.4	SPP Staff	Posting 12/20 for Jan. 2 Joint CPPTF-ESWG-TWG	Requesting approval of Scope-phase 1 (up to Needs Assessment)
1/02/2025 v0.5	SPP Staff	Posting 1/02 following Jan. 2 Joint CPPTF-ESWG-TWG	Updates made during joint meeting to address Evergy comments and stakeholder discussion
1/03/2025 v0.5	SPP Staff	Posting Scope - Phase 1 for MOPC	As approved by CPPTF-ESWG-TWG on 1/02/2025.
1/14/2025 v0.5	SPP Staff	MOPC approved Scope – phase 1	
1/21/2025 v0.6	SPP Staff	Phase 2 – draft	Needs Assessment draft language for TWG/ESWG review
2/14/2025 v0.7	SPP Staff	Phase 2 – draft	Updated draft Scope for review at 2/21 Joint ESWG-TWG
4/17/2025 v0.8	SPP Staff	Phase 2 – draft	Updated draft Scope for review at 4/22 CPPTF and 4/30 Joint ESWG-TWG
5/28/2025 v1.0	SPP Staff	Phase 2 – final	Present to ESWG-TWG for approval
6/10/2025 v1.1	SPP Staff	Phase 2 – final	Present to CPPTF for approval of policy direction
6/18/2025 v1.2	SPP Staff	Phase 2 – final	Present to ESWG-TWG for approval
7/02/2025 v1.2	SPP Staff	Final Scope (Phase 1 updates since 1/14/25 MOPC approval, and Phase 2 – final	

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SECTION 1: OVERVIEW

This document outlines the scope and schedule of work for the 2026 ITP Assessment, the 2026 20-Year Assessment,[1] and the Consolidated Planning Process (CPP) Transition Assessment (2026 Combined Assessment). Scope development for the 2026 Combined Assessment is being performed in two phases. Phase 1 includes milestones up to needs assessment and will go to the January 2025 MOPC for approval. Phase 2 will cover all remaining milestones and is expected to be complete by the July 2025 MOPC.

The CPP Transition Assessment will be an incremental analysis and extension to the 2026 ITP Assessment and include the requirements of the 20-Year Assessment. The 2026 Combined Assessment will be conducted in accordance with established protocols and will incorporate input from various working groups and committees to ensure a comprehensive and effective planning process as outlined in section 1 of the ITP Manual.[2] In addition, the Consolidated Planning Process Task Force (CPPTF) provided oversight and input with regard to the implementation of the Strategic & Creative Re-Engineering of Integrated Planning Team (SCRIPT) recommendations.[3]

The 2026 Combined Assessment aims to develop a regional transmission plan that provides reliable and economical energy delivery and facilitates the achievement of public policy objectives while maximizing benefits to the end-use customer. The 2026 Combined Assessment scope contains assumptions to be utilized that are not standardized in the ITP Manual, the Generator Interconnection Manual (SPP Business Practice 7250),[4] or the 20-Year Assessment Manual.[5] These documents should be reviewed together for a comprehensive view of the 2026 Combined Assessment's processes and assumptions.

[1] Attachment O, Section IV.2.a. of the SPP tariff requires a 20-Year assessment every five years. The next 20-year assessment is required to be completed no later than the calendar year of 2027.

[2] Integrated Transmission Planning (ITP) Manual

[3] SCRIPT Report of Recommendations (dated September 24, 2021)

[4] SPP Business Practice 7250 - Generator Interconnection Study Process

[5] 20-Year Assessment Manual

CPP TRANSITION ASSESSMENT

The CPP Transition Assessment will utilize the approved technical framework: Invest, Connect, Manage (ERIS)[6] or Deliver (NRIS+).[7] This framework is included in the subsequent section of the scope for model development, analysis, and portfolio development. The approach will be part of the 2026 Combined Assessment, which will inform future decisions on financial contributions from Generator Interconnection (GI) customers for long-term transmission expansion. The framework will outline the technical approach for evaluating system impacts from prospective ERIS and NRIS+ service types.

Looking forward, the CPP technical policies from this scope will be transitioned to planning criteria, ITP Manual, 20-Year Assessment Manual, and GI Manual (SPP Business Practice 7250) language with the goal of Q4 2025 or Q1 2026 approval.

The Generator Interconnection Advisory Group (GIAG) and the Transmission Working Group (TWG) will review and provide feedback on elements related to incorporating the GI process considerations into the CPP Transition Assessment, ensuring that the transition meets both operational and regulatory requirements.

Figure 2 below provides a holistic overview for the modeling framework for the 2026 Combined Assessment.

[6] Energy Resource Interconnection Service (ERIS)
[7] Network Resource Integration Service Plus (NRIS+)

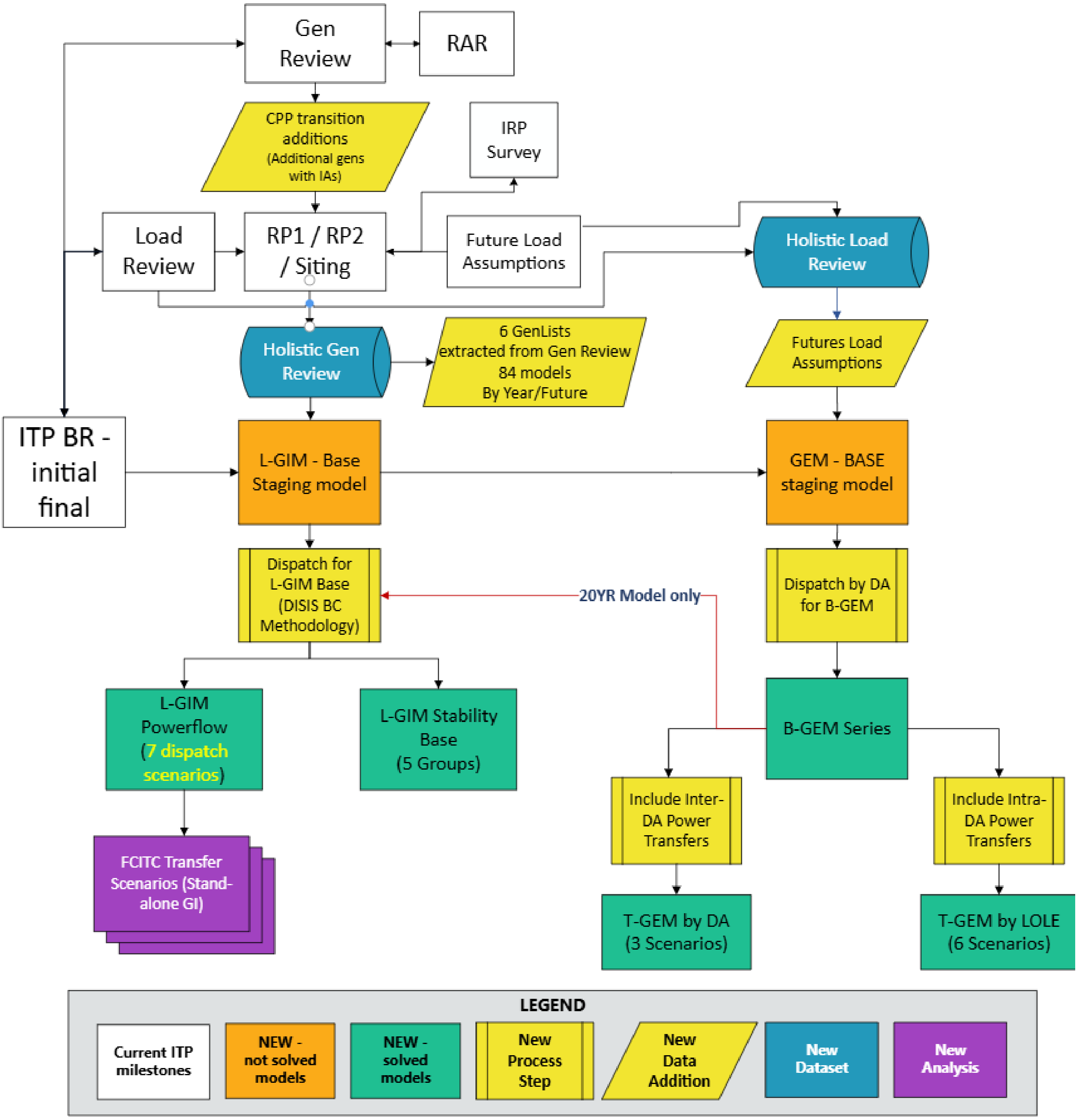

Figure 2: Technical Assessment Model Development Flow

One important note for this process flow is that additional generators with an interconnection agreement (IA) include generators with a suspended IA. See the Market Economic Models section below for additional details.

MODEL SET	DISPATCH (APPROVED)	RELIABILITY ANALYSIS DISPATCH (APPROVED)	NEEDS CRITERIA	SOLUTION EVALUATION	PORTFOLIO DEVELOPMENT	PORTFOLIO OPTIMIZATION	PORTFOLIO CONSOLIDATION
B-GEM	DA level using MDAG Manual / ITP dispatch procedures to include all modeled resources	ITP Manual Base Reliability (BR) Procedures	ITP Manual BR Procedures	ITP Manual BR Procedures	ITP Manual BR Procedures Reliability Metrics	SCRIPT O1	New Reliability Methodology for three consolidation scenarios for two futures
T-GEM	B-GEM plus Transfers using MDAG Manual / ITP dispatch procedures to include all modeled resources	ITP Manual BR Procedures	ITP Manual BR Procedures	ITP Manual BR Procedures	ITP Manual BR Procedures Reliability Metrics	SCRIPT O1	New Reliability Methodology for three consolidation scenarios for two futures
L-GIM Steady State	HVER, LVER, NRIS PQ models with CQ modeled as PQ using BP7250 dispatch procedures (Transition and ongoing Annual)	Standalone DC FCITC per BP7250 with electrically equivalent POI Criteria (Transition and ongoing Annual)	Same as BP7250 Thermal Only No Cumulative Impact Criteria with Need correlation to or replication as Economic Model Constraint	ITP Manual BR Procedures (requires automation)	Same as BP7250 Least cost No ITP Manual BR Procedure Reliability Metrics	SCRIPT O1	New Reliability Methodology for three consolidation scenarios for two futures

MODEL SET	DISPATCH (APPROVED)	RELIABILITY ANALYSIS DISPATCH (APPROVED)	NEEDS CRITERIA	SOLUTION EVALUATION	PORTFOLIO DEVELOPMENT	PORTFOLIO OPTIMIZATION	PORTFOLIO CONSOLIDATION
L-GIM Stability	Same as BP7250 (GI DISIS Manual)	ITP Manual BR Procedures and BP7250 TDF Criteria (Steady-State as proxy for Transition Only)	Same as BP7250 Voltage and Non-converged with Need correlation to or replication as Economic Model Constraint	ITP Manual BR Procedures	Same as BP7250 Least cost No ITP Manual BR Procedure Reliability Metrics to include Cost-Effective Reliability Evaluation	SCRIPT O1	New Reliability Methodology for three consolidation scenarios for two futures

Table 1: GI inclusion in the CPP/ITP

SECTION 2: MODELING DETAILS AND SCENARIOS (FUTURES) ASSUMPTIONS

MODEL YEAR DEFINITIONS

The 2026 ITP seasonal models for the 2026 ITP years two, five, and 10, as well as the CPP Transition Assessment year 20 are listed below based on the SPP Model Development Procedure Manual developed by the Model Development Advisory Group (MDAG).[8]

2026 ITP/CPP Transition Assessment & NERC TPL Assessment Study Years	
ITP & TPL Assessment (Study Year)	2026
Year 1	2026
Year 2	2027
Year 5	2030
Year 10	2035
Year 20	2045

Table 2: Model Year Definitions

At the July 2024, Markets & Operations Policy Committee (MOPC) meeting, SPP staff's request for a waiver of language in section 2 of the ITP Manual, requiring Light Load models for years 5 and 10 of the ITP Base Reliability (BR) Powerflow, and the Market Powerflow Models Futures 1 and 2 was approved.

COMBINED ASSESSMENT POLICY ON MODEL SHELF-LIFE AND LATE DATA RECOMMENDATIONS

For the 2026 Combined Assessment, ITP Manual, Section 10.3, late model change requests must be submitted by July 31, 2025. Rating changes may be submitted and implemented during or at the end of the ITP and CPP shelf-life periods. Further enhancements to the late data submission process will be addressed in a future revision request for the ITP Manual, Section 10.3.

[8] SPP Model Development Procedure Manual.

MARKET ECONOMIC MODELS

The Market Economic Models (MEMs) for the 2026 Combined Assessment will include generators with an IA on suspension. These resources have been planned through the Generator Interconnection process.

Approval of this scope document serves as a waiver from existing ITP Manual Section 2.2.1.4 (Generation Resource Inclusion).

MARKET POWERFLOW MODELS

SPP requested a waiver for the ITP Manual, Section 2.3.2, for the Market Powerflow Models (MPMs) for the 2026 ITP Assessment, and this was approved at the January 2025 MOPC meeting. The MPMs will also be removed from use in future CPP assessments for the reasons described below.

The MPMs have historically served as a way to perform an AC verification of the MEMs and the resource expansion plan developed for the ITP. This has included the development of peak and off-peak base models representing select hours of operation from the MEM, performing AC contingency and voltage stability analysis on the model set. These analyses have provided base steady-state AC violations, and potential voltage stability transfer limitations of the final recommended portfolio However, the MPMs are a very challenging and time-consuming set of powerflow models to build. Use of the MPMs create a tight bottleneck in the ITP assessment schedule because they cannot be built until the MEM is complete, potentially delaying needs posting, and AC verification through voltage stability analysis cannot be performed until the final consolidated portfolio is determined, potentially impacting transmission decisions and other final assessments.

The CPP is introducing new model sets that serve multiple purposes. The B-GEM and T-GEM will provide ACCC analysis of existing and resource expansion generation on a baseline dispatch and a set transfers induced across the system in a range of biases. The L-GIM will provide individual unit transfer analysis of the resource expansion plan analyzed up to maximum capability through DC FCITC analysis, above current operating points analyzed in the MPM.

It is noted that the MPMs are Security Constrained Economic Dispatch (SCED) based models, which use information derived from the MEMs and ABB data. However, the new BGEMs, TGEMs and LGIM model sets will stress the expected system of the future to maintain reliability and resiliency. This includes performing more holistic and comprehensive analyses of the entire SPP system. Therefore, SPP does not believe that it is necessary for these new models to be SCED capable in order to obtain more than adequate analysis of the SPP system, including for validation of economic analyses. The comprehensive nature of these new model sets include more than adequate AC verification of future Resource Plans, performing analyses to cover the AC currently performed utilizing the MPMs. Consequently, since the MPMs have not been used recently and the new BGEM, TGEM and LGIM models provide greater functionality and more comprehensive verification capabilities, the use of the MPMs has become much less valuable.

The MPMs are being removed from analysis in the CPP for the following reasons:

- The challenges of developing the model set, including time, effort and expertise needed
- The select number of MEM hours provide a somewhat limited view of system conditions that only utilize an RTO coincident load profile and expected unit operation
- Their inclusion creates a narrow bottleneck in the study process, resulting in additional risk that cannot be afforded in the CPP
- The GEM and GIM models will serve to analyze the resource expansion plan in an AC model series
- The GEMs reflect expected operation of the SPP resource fleet at non-coincident load levels
- The GEMs provide a range of transfer scenarios that could be considered to reflect a range of system-wide market flow biases that account for analysis that will no longer be performed
- The GIMs will analyze resource expansion plan generation at maximum capacity

GENERATION EXPANSION MODELS (GEM)

The GEM methodology is a proactive approach to planning the system for existing and future resource expectations and load and maintaining a level of transfer capability across the system. The GEM series will be developed incrementally to the ITP BR model series.

ADOPTION OF BASE GENERATION EXPANSION MODELS (B-GEM)

The B-GEM approach assumes a level of capacity value of all expected future resources, treating all existing and forecasted generators equally, to serve baseline load requirements. This model set serves as a foundation to meet the needs of both existing and future baseline generator and load deliverability and will be used as the base model for transfer analysis to further support system resiliency and reliable interconnection.

- **Inclusion of resources:** Incremental to the ITP base reliability, all generators with non-firm service eligible for inclusion in the BR models and those from the resource expansion plan assigned to a load group in a manner consistent with the ITP BR methodology for conventional and renewable resources will be included for dispatch.
- **Priority of dispatch**: All generators available for dispatch will be considered concurrently.
- **Definition of load groups**: Generators available for dispatch will be dispatched at a Deliverability Area (DA) level, consistent with NRIS+.
- **Inclusion of load groups**: All load areas of the system will be aggregated, and served, at a DA level.

- **Inclusion of MEM Future Driver Peak Demand Growth Rates**: Future driver large loads will be added, and electrification will be distributed pro rata across existing conforming bus loads with stakeholder exceptions consistent with MEM inclusion.

The B-GEMs will be dispatched at the DA level, utilizing all modeled generation to meet the requirements of all load-responsible entities, as shown in Table 3 below. This approach aligns with current base reliability model development practices or any improvements under development. It will model renewable and storage[9] generation using the ITP 5 year-year average or replacement data[10] expected output methodology[11] and economically dispatch remaining conventional generation up to nameplate capacity amounts while maintaining ITP BR dispatch of units identified as must run.[12]

	FUTURES 1 & 2			
DESCRIPTION	**YEAR 5**	**YEAR 10**	**YEAR 20**	**TOTAL**
B-GEM	Summer Winter	Summer Winter	Summer Winter	**12**

Table 3: B-GEM Models

ADOPTION OF TRANSFER GENERATION EXPANSION MODELS (T-GEM)

The T-GEM models consist of the same model inclusion requirements for generation as noted for B-GEM models. The T-GEM models are created to provide models for deliverability transfer scenarios. This approach integrates and coordinates transfer analysis from GI studies and expands the ITP to include system resiliency analysis, enhancing and streamlining scenario planning previously used in SPP regional planning.

These transfer scenarios are designed to reflect expected system operations under normal and extreme conditions, not the full injection of any specific resource. The analysis will include resource expansion plans developed for the applicable future and year, regardless of customer activity.

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[9] Consistent with the SPP Model Development Procedure Manual, existing and resource plan storage resources that are identified as standalone will be modeled at the maximum discharging capability and existing and resource plan storage resources that are identified as co-located will be modeled using the point of interconnection injection limit modeling with the limit being equal to the higher of the sum of non-storage resources or storage resources at the point of interconnection. No charging of storage devices will be modeled.

[10] This includes utilizing BP7250 fuel-based dispatch for solar at 40% Nameplate for Summer Peak and 10% Nameplate for Winter Peak and for wind at 40% Nameplate for Summer Peak and 45% Nameplate for Winter Peak in lieu of replacement data that would result in zero dispatch.

[11] The expected output will be based on the facility's Nameplate Capacity to not exceed Maximum Injection Capability and can exceed a facility's firm service amount.

[12] Units labeled as must run as identified in the ITP Base Reliability and Economic dispatch methodologies, including but not limited to hydroelectric, cogeneration facilities, landfill gas and nuclear units.

TRANSFER CASE MODEL DEVELOPMENT

The model set will consist of two scenario types to address the needs of the footprint and the needs of each DA.

This will allow the CPP to better meet proactive planning objectives, ensure the transmission system is planned holistically, and better isolate the process from customer withdrawal and suspension activity.

INTER-DELIVERABILITY AREAS TRANSFERS

The first scenario set will consist of transfers between DAs, as defined in Figure 3 below. These transfer scenarios are similar to analysis performed in both the current DISIS group ERIS analysis,2024 ITP winter weather analysis, and 2025 ITP Resiliency Needs Assessment Criteria 2: Transferability. Generation from each individual DA will be increased while generation in the other two DAs will be decreased in order to induce power transfers across the footprint to maintain each DA's ability to provide for the system. The level of power transfers at a minimum will be based on the lower of the sink load or source generation accreditation plus the planning reserve margin (PRM) in the PRM Values section. Additional power transfer capability requirements may be approved by the appropriate stakeholder working groups.

Deliverability Areas

DAs used as the sink for modeling existing and new NRIS+ requests will consist of the generation of Transmission Owners located in the following SPP tariff Attachment H Zones, as shown in **Error! Reference source not found.** below (number (#) designations as per Attachment H):

South Deliverability Area

- #1 American Electric Power – West
- #5 Grand River Dam Authority
- #7 Oklahoma Gas and Electric
- #10 Southwestern Power Administration
- #11 Southwestern Public Service Company
- #13 Western Farmers Electric Cooperative

Central Deliverability Area

- #2 Kansas City Board of Public Utilities
- #3 City Utilities of Springfield, Missouri
- #4 Empire District Electric Company
- #6 Evergy Metro
- #8 Midwest Energy
- #9 Evergy Missouri West
- #12 Sunflower Electric Power Corporation
- #14 Evergy Kansas Central

North Deliverability Area

- #16 Lincoln Electric System
- #17 Nebraska Public Power District
- #18 Omaha Public Power District

#19 Upper Missouri Zone (Eastern Interconnection)

Dispatch Methodology

These scenarios will utilize the economic dispatch methodology consistent with MDAG/ITP methodology for source and sink conventional generation and scaling methodology for source and sink renewable generation using a conventional to renewable ratio based on B-GEM expected levels. In the source definitions, generation will be dispatched with a potential increase not to exceed an assumed level of reserves on an aggregate basis.[13]

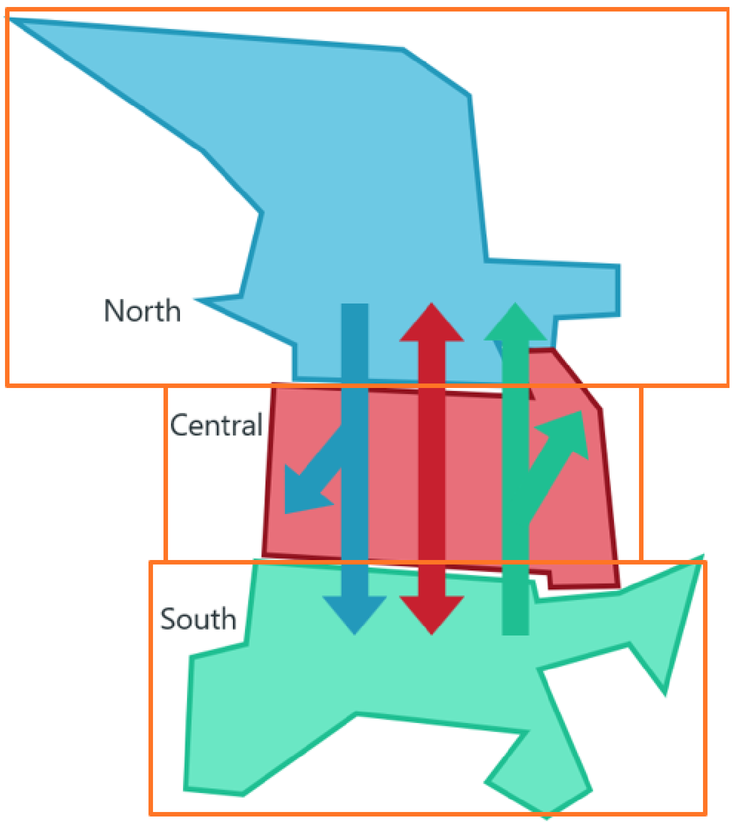

Figure 3: Deliverability Areas Transfer Scenarios – Inter-Deliverability Area

INTRA-DELIVERABILITY AREAS TRANSFERS

The second scenario set will consist of transfers between zones within each DA, as defined in **Error! Reference source not found.** and

DESCRIPTION	YEAR 5	YEAR 10	YEAR 20	TOTAL
T-GEM Inter-DA	Summer (3 DAs) Winter (3 DAs)	Summer (3 DAs) Winter (3 DAs)	Summer (3 DAs) Winter (3 DAs)	**36**

[13] ITP BR dispatch of units identified as must run as previously stated will be maintained.

T-GEM Intra-DA LOLE-to-LOLE	Summer (3 DAs, 2 LOLE per DA) Winter (3 DAs, 2 LOLE per DA)	Summer (3 DAs, 2 LOLE per DA) Winter (3 DAs, 2 LOLE per DA)	Summer (3 DAs, 2 LOLE per DA) Winter (3 DAs, 2 LOLE per DA)	**72**
			TOTAL:	**108**

Table 4: T-GEM Models

LOCAL GENERATOR INTERCONNECTION MODELS (L-GIM)

The steady-state Local Generator Interconnection Models (L-GIM) will use Base and Prior Queue (PQ) models consistent with SPP Business Practice 7250, DISIS Steady-State Model Methodologies by modeling Current Queue (CQ) as PQ and studying CQ at Resource Plan Nameplate Capacity to not exceed Maximum Injection Capability for Resource Plan co-located wind and solar with storage for ERIS and at Resource Plan Accredited Capacity to not exceed Maximum Injection Capability for co-located wind and solar with storage for NRIS basis, similar to ITP Generator Outlet Facility (GOF) DC FCITC analysis performed during the Resource Siting milestone. The CQ will be Future Resource Plan per future per year. Year 5 will be considered as PQ for Year 10, and Year 5 and Year 10 as PQ for Year 20. For Year 5 and Year 10, the ITP BR, with the Resource Addition Requests (RARs) and Resource Plan topology added, will be considered the Base Model in **Error! Reference source not found.** below. The RARs will be considered PQ, and the Resource Plan will be considered CQ for both ERIS and NRIS+ Service Types dispatched consistent with SPP Business Practice 7250. For Year 20, the B-GEM model with the RARs and Resource Plan dispatched consistent with B-GEM methodology will be considered the Base Model in **Error! Reference source not found.**.

DESCRIPTION	FUTURES 1 & 2			TOTAL
	YEAR 5	YEAR 10	YEAR 20	
BASE	Summer Winter	Summer Winter	Summer Winter	**12**

Table 5: L-GIM Steady-State Base Models

SERVICE TYPE	DISPATCH SCENARIO	FUTURES 1 & 2			PRIOR QUEUE MODEL TOTALS	CURRENT QUEUE MODEL TOTALS
		YEAR 5	YEAR 10	YEAR 20		
ERIS	**HVER**	Summer (5 groups) Winter (5 groups)	Summer (5 groups) Winter (5 groups)	Summer (5 groups) Winter (5 groups)	**60**	0
	LVER	Summer (SPP Region)	Summer (SPP Region)	Summer (SPP Region)	**12**	0

SERVICE TYPE	DISPATCH SCENARIO	FUTURES 1 & 2			PRIOR QUEUE MODEL TOTALS	CURRENT QUEUE MODEL TOTALS
		YEAR 5	YEAR 10	YEAR 20		
		Winter (SPP Region)	Winter (SPP Region)	Winter (SPP Region)		
NRIS+	**NR**	Summer (SPP Region) Winter (SPP Region)	Summer (SPP Region) Winter (SPP Region)	Summer (SPP Region) Winter (SPP Region)	**12**	0
TOTAL:					**84**	

Table 6: L-GIM Steady-State Study Models

For the purposes of the CPP Transition Assessment, the Stability L-GIM models will use steady-state Base and CQ models consistent with SPP Business Practice 7250, DISIS Stability Model Methodologies to capture voltage criteria violations and proxy stability criteria violations as non-converged planning events. PQ models will not be built to manage the number of models being developed. Without the PQ models, a Power Transfer Voltage Response Factor (PTVF) will not be calculated, and all CQ model voltage criteria violations will be addressed as if the PTVF of 0.02 has been met. The CQ will be the Future Resource Plan per future per year at Resource Plan Nameplate Capacity to not exceed Maximum Injection Capability for Resource Plan co-located wind and solar with storage for ERIS. Year 5 will be considered as PQ for Year 10, and Year 5 and Year 10 as PQ for Year 20. For Year 5 and Year 10, the ITP BR, with the RARs and Resource Plan topology added, will be considered the Base Model in **Error! Reference source not found.** below. The RARs will be considered PQ, and the Resource Plan will be considered CQ consistent with SPP Business Practice 7250. For Year 20, the B-GEM model with the RARs and Resource Plan dispatched consistent with B-GEM methodology will be considered the Base Model in **Error! Reference source not found.** below. The approximate location of current GI regional cluster groups is shown in Figure 5 below.

DESCRIPTION	FUTURES 1 & 2			TOTAL
	YEAR 5	YEAR 10	YEAR 20	
BASE	Summer Winter	Summer Winter	Summer Winter	**12**

Table 7: L-GIM Stability Base Models

SERVICE TYPE	DISPATCH SCENARIO	FUTURES 1 & 2			PRIOR QUEUE MODEL TOTALS	CURRENT QUEUE MODEL TOTALS
		YEAR 5	YEAR 10	YEAR 20		
ERIS	**N/A**	Summer (5 groups)	Summer (5 groups)	Summer (5 groups)	0	**60**

		Winter (5 groups)	Winter (5 groups)	Winter (5 groups)		
						60

Table 8: L-GIM Stability Study Models

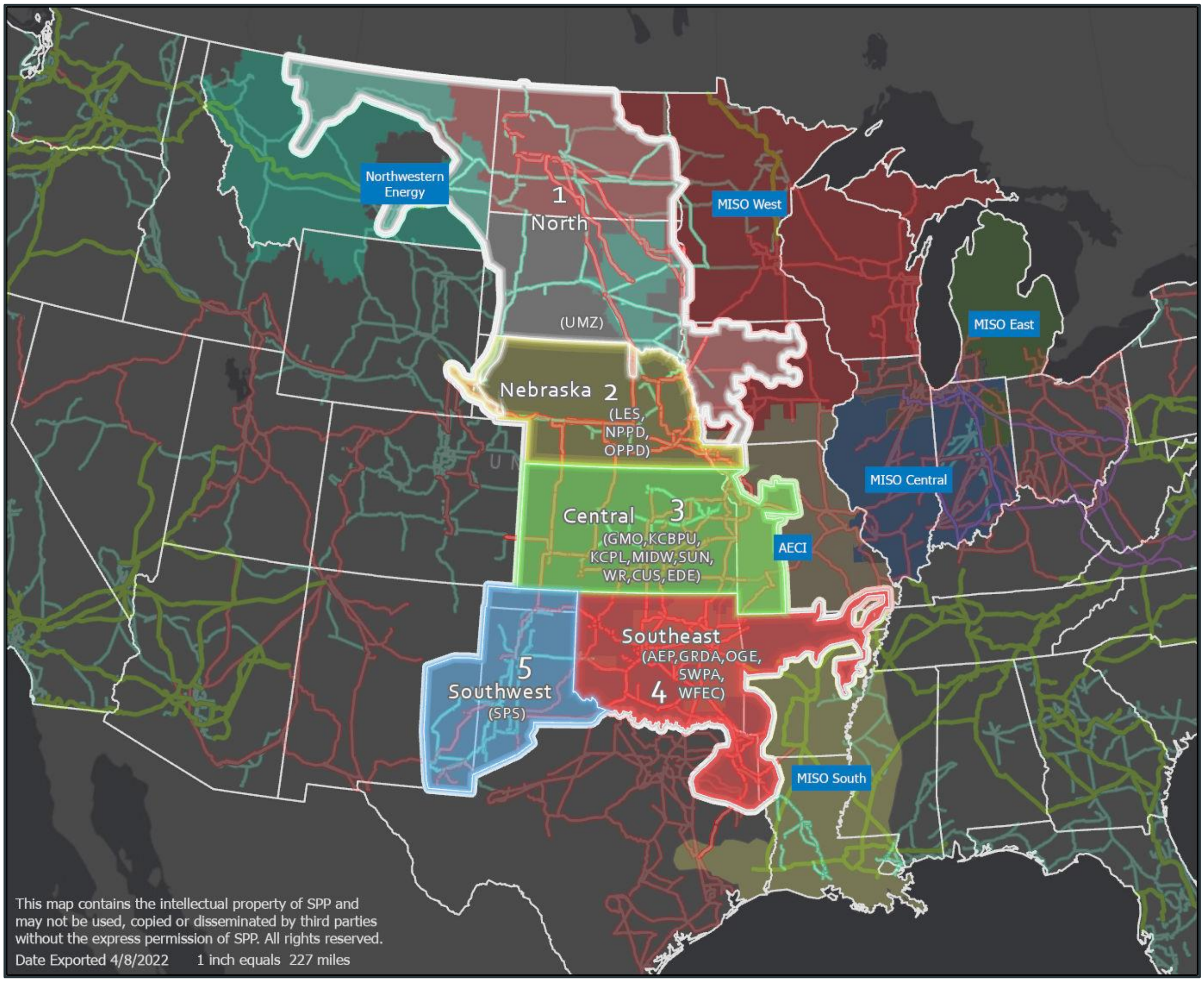

Figure 5: Approximate Location of Current Regional Cluster Groups

YEAR 20 MODELS

A 20-year Summer and Winter B-GEM, market economic, T-GEM, and L-GIM model will be developed from the 10-year Summer and Winter datasets. Modeling assumptions will follow the 20-Year Assessment Manual and this scope document. The 20-year peaks in the ITP load review and peak demand growth rates to include future driver large loads and electrification will be uniformly distributed across existing conforming bus loads consistent with the MEM. For Summer peaking and Winter peaking demand groups, a 20-year Summer peak for Winter peaking demand groups and Winter peak for Summer peaking demand groups will be based on the 10-Year Summer peak and Winter peak ratio. Due to anticipated shortfall expected in the 20-year base reliability model, solving the model will be difficult using existing shortfall methodologies. In that regard, the 20-year B-GEM will be considered a 20-year BR model and the starting point for the 20-year L-GIM models. Pursuant to the *System Topology* section of the 20-Year Assessment Manual, the models will include SPP upgrades that have been approved for construction for approved Joint Targeted Interconnection Queue (JTIQ) projects, as well as Midcontinent Independent System Operation (MISO) approved long-range transmission plan projects with expected in-service dates beyond year 10.

below. It is recommended to use the zones used for Loss of Load Expectation (LOLE) studies which are subsets of each DA. These zones provide a natural geographical separation of each DA, the boundaries of which represent historically weak points in the SPP transmission system. This set of scenarios will serve to protect and enhance deliverability of generators to all load within each DA. The level of power transfers at a minimum will be based on the lower of the sink load or source generation accreditation plus the PRM in the *Planning Reserve Margin Values* section. Additional power transfer capability requirements may be approved by stakeholders.

Dispatch Methodology

These scenarios will utilize the economic dispatch methodology consistent with MDAG/ITP methodology for source and sink conventional generation and scaling methodology for source and sink renewable generation using a conventional to renewable ratio based on B-GEM expected levels. In the source definitions, generation will be dispatched with a potential increase not to exceed an assumed level of reserves on an aggregate basis.[14]

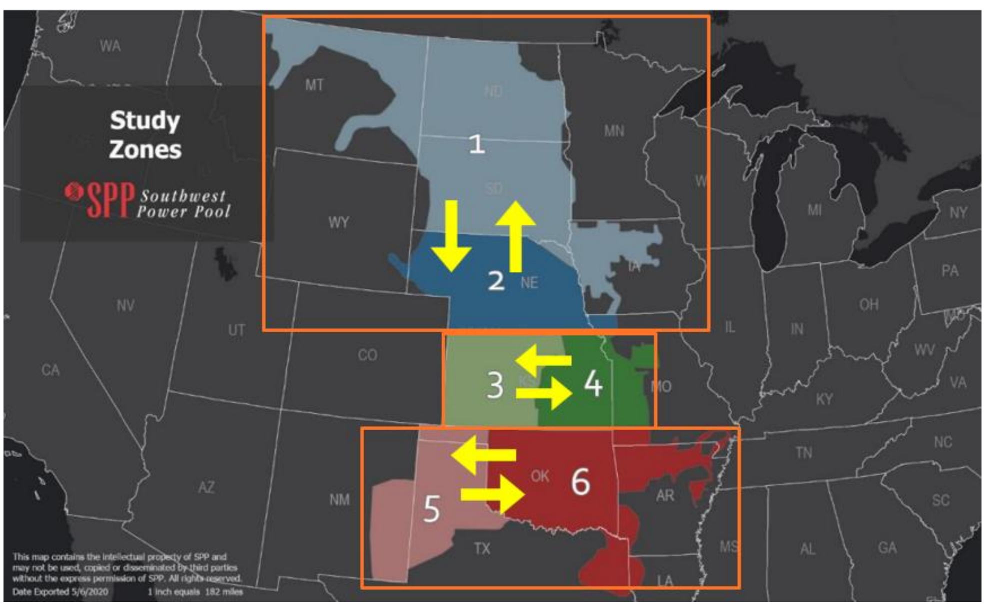

Figure 4: LOLE Study Zones Transfer Scenarios – Intra-DA Inter-LOLE (Intra-Deliverability Area transfers)

DESCRIPTION	YEAR 5	YEAR 10	YEAR 20	TOTAL

[14] ITP BR dispatch of units identified as must run as previously stated will be maintained.

T-GEM Inter-DA	Summer (3 DAs) Winter (3 DAs)	Summer (3 DAs) Winter (3 DAs)	Summer (3 DAs) Winter (3 DAs)	**36**
T-GEM Intra-DA LOLE-to-LOLE	Summer (3 DAs, 2 LOLE per DA) Winter (3 DAs, 2 LOLE per DA)	Summer (3 DAs, 2 LOLE per DA) Winter (3 DAs, 2 LOLE per DA)	Summer (3 DAs, 2 LOLE per DA) Winter (3 DAs, 2 LOLE per DA)	**72**
			TOTAL:	**108**

Table 4: T-GEM Models

LOCAL GENERATOR INTERCONNECTION MODELS (L-GIM)

The steady-state Local Generator Interconnection Models (L-GIM) will use Base and Prior Queue (PQ) models consistent with SPP Business Practice 7250, DISIS Steady-State Model Methodologies by modeling Current Queue (CQ) as PQ and studying CQ at Resource Plan Nameplate Capacity to not exceed Maximum Injection Capability for Resource Plan co-located wind and solar with storage for ERIS and at Resource Plan Accredited Capacity to not exceed Maximum Injection Capability for co-located wind and solar with storage for NRIS basis, similar to ITP Generator Outlet Facility (GOF) DC FCITC analysis performed during the Resource Siting milestone. The CQ will be Future Resource Plan per future per year. Year 5 will be considered as PQ for Year 10, and Year 5 and Year 10 as PQ for Year 20. For Year 5 and Year 10, the ITP BR, with the Resource Addition Requests (RARs) and Resource Plan topology added, will be considered the Base Model in **Error! Reference source not found.** below. The RARs will be considered PQ, and the Resource Plan will be considered CQ for both ERIS and NRIS+ Service Types dispatched consistent with SPP Business Practice 7250. For Year 20, the B-GEM model with the RARs and Resource Plan dispatched consistent with B-GEM methodology will be considered the Base Model in **Error! Reference source not found.**.

DESCRIPTION	FUTURES 1 & 2			TOTAL
	YEAR 5	YEAR 10	YEAR 20	
BASE	Summer Winter	Summer Winter	Summer Winter	**12**

Table 5: L-GIM Steady-State Base Models

SERVICE TYPE	DISPATCH SCENARIO	FUTURES 1 & 2			PRIOR QUEUE MODEL TOTALS	CURRENT QUEUE MODEL TOTALS
		YEAR 5	YEAR 10	YEAR 20		
ERIS	**HVER**	Summer (5 groups) Winter	Summer (5 groups) Winter	Summer (5 groups) Winter	**60**	0

SERVICE TYPE	DISPATCH SCENARIO	FUTURES 1 & 2			PRIOR QUEUE MODEL TOTALS	CURRENT QUEUE MODEL TOTALS
		YEAR 5	YEAR 10	YEAR 20		
		(5 groups)	(5 groups)	(5 groups)		
	LVER	Summer (SPP Region) Winter (SPP Region)	Summer (SPP Region) Winter (SPP Region)	Summer (SPP Region) Winter (SPP Region)	**12**	0
NRIS+	**NR**	Summer (SPP Region) Winter (SPP Region)	Summer (SPP Region) Winter (SPP Region)	Summer (SPP Region) Winter (SPP Region)	**12**	0
TOTAL:					**84**	

Table 6: L-GIM Steady-State Study Models

For the purposes of the CPP Transition Assessment, the Stability L-GIM models will use steady-state Base and CQ models consistent with SPP Business Practice 7250, DISIS Stability Model Methodologies to capture voltage criteria violations and proxy stability criteria violations as non-converged planning events. PQ models will not be built to manage the number of models being developed. Without the PQ models, a Power Transfer Voltage Response Factor (PTVF) will not be calculated, and all CQ model voltage criteria violations will be addressed as if the PTVF of 0.02 has been met. The CQ will be the Future Resource Plan per future per year at Resource Plan Nameplate Capacity to not exceed Maximum Injection Capability for Resource Plan co-located wind and solar with storage for ERIS. Year 5 will be considered as PQ for Year 10, and Year 5 and Year 10 as PQ for Year 20. For Year 5 and Year 10, the ITP BR, with the RARs and Resource Plan topology added, will be considered the Base Model in **Error! Reference source not found.** below. The RARs will be considered PQ, and the Resource Plan will be considered CQ consistent with SPP Business Practice 7250. For Year 20, the B-GEM model with the RARs and Resource Plan dispatched consistent with B-GEM methodology will be considered the Base Model in **Error! Reference source not found.** below. The approximate location of current GI regional cluster groups is shown in Figure 5 below.

DESCRIPTION	FUTURES 1 & 2			TOTAL
	YEAR 5	YEAR 10	YEAR 20	
BASE	Summer Winter	Summer Winter	Summer Winter	**12**

Table 7: L-GIM Stability Base Models

SERVICE TYPE	DISPATCH SCENARIO	FUTURES 1 & 2			PRIOR QUEUE MODEL TOTALS	CURRENT QUEUE MODEL TOTALS
		YEAR 5	YEAR 10	YEAR 20		
ERIS	**N/A**	Summer (5 groups) Winter (5 groups)	Summer (5 groups) Winter (5 groups)	Summer (5 groups) Winter (5 groups)	0	**60**
						60

Table 8: L-GIM Stability Study Models

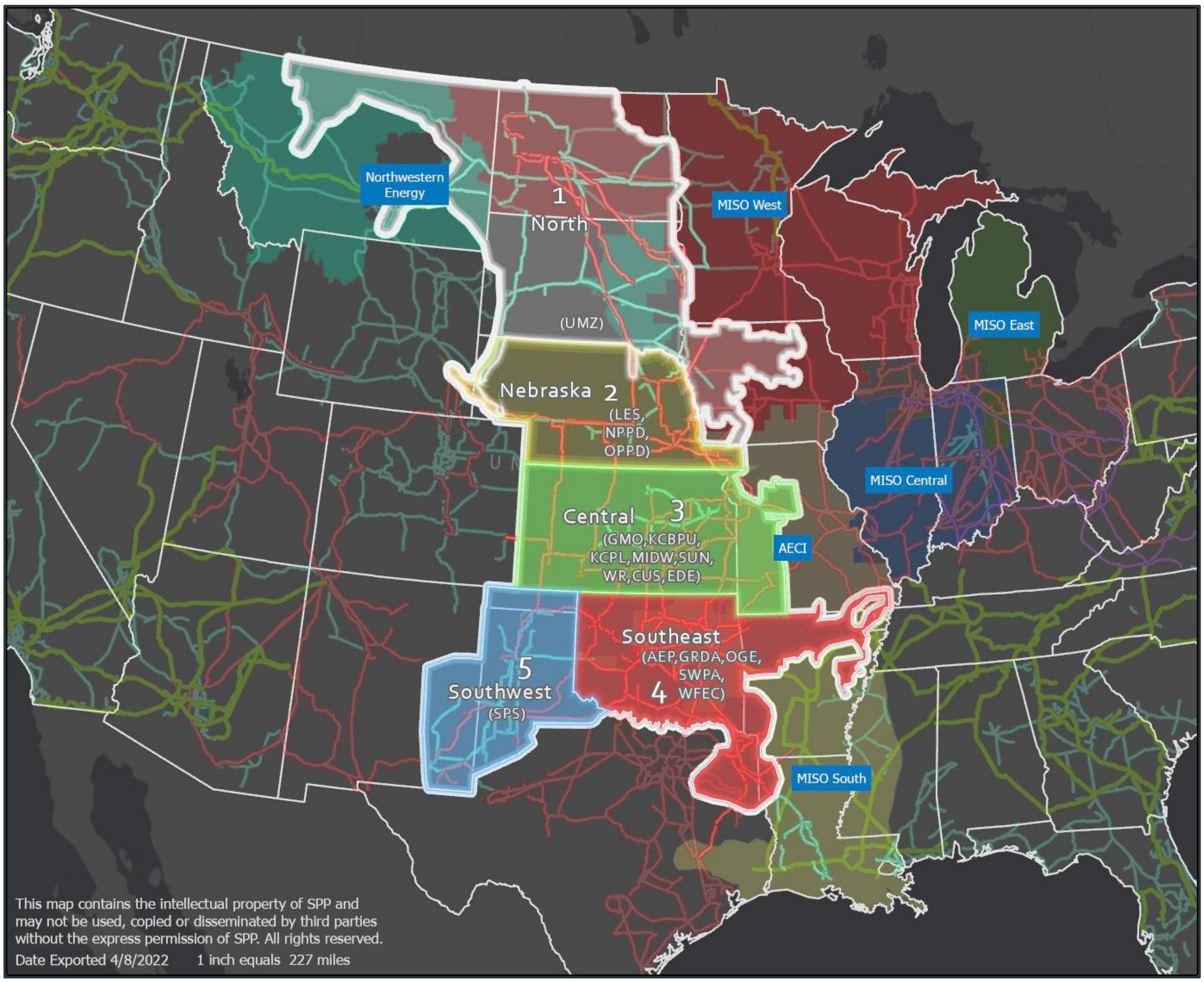

Figure 5: Approximate Location of Current Regional Cluster Groups

YEAR 20 MODELS

A 20-year Summer and Winter B-GEM, market economic, T-GEM, and L-GIM model will be developed from the 10-year Summer and Winter datasets. Modeling assumptions will follow the 20-Year Assessment Manual and this scope document. The 20-year peaks in the ITP load review and peak demand growth rates to include future driver large loads and electrification will be uniformly distributed across existing conforming bus loads consistent with the MEM. For Summer peaking and Winter peaking demand groups, a 20-year Summer peak for Winter peaking demand groups and Winter peak for Summer peaking demand groups will be based on the 10-Year Summer peak and Winter peak ratio. Due to anticipated shortfall expected in the 20-year base reliability model, solving the model will be difficult using existing shortfall methodologies. In that regard, the 20-year B-GEM will be considered a 20-year BR model and the starting point for the 20-year L-GIM models. Pursuant to the *System Topology* section of the 20-Year Assessment Manual, the models will include SPP upgrades that have been approved for construction for approved Joint Targeted Interconnection Queue (JTIQ) projects, as well as Midcontinent Independent System Operation (MISO) approved long-range transmission plan projects with expected in-service dates beyond year 10.[15]

[Remainder of page intentionally left blank.]

[15] 20-Year Assessment Manual, *System Topology* section.

MODEL USE SUMMARY

Table 9 and Table 10: below provide a summary of the models used and purpose of each for the 2026 Combined Assessment.

MODEL	MODEL TYPE	DISPATCH SCENARIO	YEAR 2	YEAR 5	YEAR 10	YEAR 20	STUDY REQUIREMENT	PORTFOLIO DEVELOPMENT?
ITP BR	**Steady-State**	**BASE**	Summer Summer-Shoulder Winter	Summer Summer-Shoulder Winter	Summer Winter	NA	**ITP/TPL**	**Yes**
TPL	**Steady-State**	**Sensitivity**	Summer Summer-Shoulder	Summer	NA	NA	**TPL**	**No**
TPL	**Stability**	**BASE**	Summer Summer-Shoulder	NA	Summer	NA	**TPL**	**No**

Table 9: Non-Futures-Driven Models

MODEL				FUTURES 1 & 2			STUDY REQUIREMENT	PORTFOLIO DEVELOPMENT[16]
	MODEL TYPE	DISPATCH SCENARIO	YEAR 2	YEAR 5	YEAR 10	YEAR 20		
ITP MEM	**PCM**	**SCUC / SCED**	Annual	Annual	Annual	Annual	**ITP**	**Yes**

[16] Portfolio development flag of "No" indicates model set is used for staging/development of other models only.

MODEL				FUTURES 1 & 2			STUDY REQUIREMENT	PORTFOLIO DEVELOPMENT[16]
	MODEL TYPE	DISPATCH SCENARIO	YEAR 2	YEAR 5	YEAR 10	YEAR 20		
L-GIM	**Steady-State**	**BASE**	NA	Summer Winter	Summer Winter	Summer Winter	**NA**	**No**
L-GIM	**Steady-State**	**ERIS/NRIS+**	NA	See Table 6	See Table 6	See Table 6	**GI**	**No**
L-GIM	**Steady-State**	**Standalone FCITC**	NA	Summer Winter	Summer Winter	Summer Winter	**GI/FAC**	**Yes**
L-GIM	**Stability proxy**	**BASE**	NA	Summer Winter	Summer Winter	Summer Winter	**GI**	**No**
L-GIM	**Stability proxy**	**ERISERIS**	NA	Summer (5 groups) Winter (5 groups)	Summer (5 groups) Winter (5 groups)	Summer (5 groups) Winter (5 groups)	**GI/FAC**	**Yes[17]**

[17] L-GIM stability models developed for the long-term assessment are steady-state models dispatched utilizing the stability dispatch methodology. Transmission system needs will be utilized for portfolio development reference and Generalized Rate for Interconnection Development Contribution (GRID-C) considerations.

MODEL	MODEL TYPE	DISPATCH SCENARIO	YEAR 2	FUTURES 1 & 2			STUDY REQUIREMENT	PORTFOLIO DEVELOPMENT[16]
				YEAR 5	YEAR 10	YEAR 20		
B-GEM	**Steady-State**	**BASE**	NA	Summer Winter	Summer Winter	Summer Winter	**ITP**	**Yes**
T-GEM	**Steady-State**	**Transfer (Inter-DA)**	NA	Summer (3 scenarios) Winter (3 scenarios)	Summer (3 scenarios) Winter (3 scenarios)	Summer (3 scenarios) Winter (3 scenarios)	**ITP**	**Yes**
T-GEM	**Steady-State**	**Transfer (Intra-DA)**	NA	Summer (6 scenarios) Winter (6 scenarios)	Summer (6 scenarios) Winter (6 scenarios)	Summer (6 scenarios) Winter (6 scenarios)	**ITP**	**Yes**

Table 10: Futures-Driven Models

MARKET ECONOMIC MODEL OVERVIEW

FUTURES

The Economic Studies Working Group (ESWG) developed two futures with input from the CPP Task Force (CPPTF), Strategic Planning Committee (SPC), and the TWG. The MOPC reviewed preliminary versions of both futures in October 2024, and their final versions in January 2025.

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KEY ASSUMPTIONS	DRIVERS						
	Future 1 (F1) – Continued Technologies Transition				Future 2 (F2) – Accelerated Decarbonization		
	Year 2	Year 5	Year 10	Year 20	Year 5	Year 10	Year 20
Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast + **High confidence**[18] large loads			As submitted in load forecast + Moderate electrification scenario from FERNS + **All submitted** large loads		
Energy Demand Growth Rates	As submitted in load forecast	As submitted in load forecast + **High confidence** large loads			As submitted in load forecast + Moderate electrification scenario from FERNS + **All submitted** large loads		
Natural Gas Prices	Current industry forecast (Hitachi & S&P Global)						
Coal Prices	Current industry forecast (Hitachi)						
Emissions Prices	Current industry forecast (Hitachi)						
Fossil Fuel Retirements	Current forecast	Based on Integrated Resource Plan (IRP) feedback; subject to generator owner (GO) review					
Environmental Regulations	Current regulations						
Demand Response[19]	As submitted in load forecast	As submitted in load forecast (Separate load forecast may be submitted for use in Resource Planning)					

[18] In the opinion of the submitter that these loads are very likely to develop

[19] As defined in the SPP Model Development Procedure Manual.

KEY ASSUMPTIONS	DRIVERS						
	Future 1 (F1) – Continued Technologies Transition				Future 2 (F2) – Accelerated Decarbonization		
	Year 2	Year 5	Year 10	Year 20	Year 5	Year 10	Year 20
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast (Separate load forecast may be submitted for use in Resource Planning)					
Energy Efficiency	As submitted in load forecast	As submitted in load forecast (Separate load forecast may be submitted for use in Resource Planning)					
Resource Siting	N/A	CPP Methodology					
General Escalation (Inflation)	N/A	2.5%					
Total Resource Capacity (GW)							
Solar (GW)	Existing + RARs	**11**	**21**	**42**	**21**	**42**	**83**
Wind (GW)	Existing + RARs	**46.6**	**50**	**67**	**50**	**67**	**100**
Storage (GW)	Existing + RARs	**5**	**10**	**20**	**11**	**22**	**43**
Storage Duration	N/A	**4-hour**	**4-hour**	**86% 4h; 14% 8h**	**4-hour**	**27% 4h; 73% 8h**	**27% 4h; 73% 8h**

Table 11: Future Drivers

ZONAL RESOURCE SITING ALLOCATION

The new CPP process focuses on identifying optimal zones for renewable resources over a 20-year horizon, ensuring they are aligned with necessary transmission capacity. The process will be resilient to customer withdrawal or suspension, enabling cost-sharing across various customer types, ensuring that GI cost contributions are allocated appropriately without hindering essential transmission expansion. The approach begins with broad zonal planning, followed by detailed assessments within zones, using metrics of First Contingency Incremental Transfer Capability (FCITC) and stakeholder input to identify the best interconnection sites. Resource Siting will be split up by LOLE zone to allocate all new additions by fuel type. These values are for additions needed to reach the renewable totals for each future after inclusion of the existing gen and RARs for each scenario.

ZONE	SOLAR	WIND	STORAGE
North	8%	9%	5%
Nebraska	13%	17%	6%
Kansas West	4%	19%	2%
Kansas East	24%	19%	27%
Southwest	21%	16%	14%
Southeast	30%	20%	46%

Table 12: Zonal Resource Siting Allocation by percentage

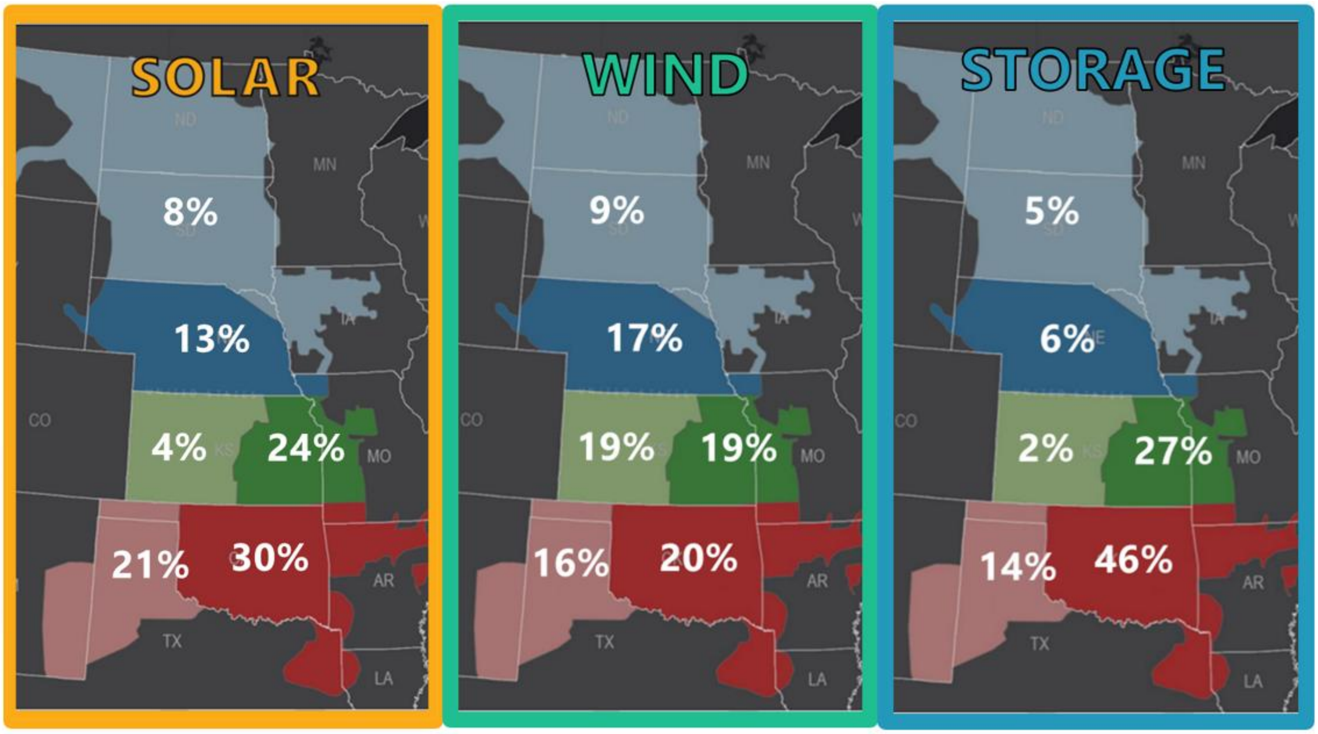

Figure 6: Zonal Resource Siting Allocation percentage by resource maps

GENERATOR OUTLET FACILITIES (GOF)

No Generator Outlet Facilities will be developed through the Resource Siting Plan or included in the model sets. Any severe congestion created through the addition of the Siting Plan that degrades economic model quality will be addressed during the constraint assessment milestone, likely by removing the flowgate and addressing the violation through L-GIM other analysis.

MUST-RUN UNITS

Must-run designations for SPP areas will be assigned to co-generation, nuclear, landfill gas, and hydroelectric units, unless an exception is requested during the generation review and approved by the ESWG. Co-generation units will be identified based on Energy Information Administration (EIA) Form EIA-860 data, as well as Hitachi simulation-ready data. If a unit was originally identified as a must-run in a previous study, but was removed as an exception, it will not be identified as a must-run unit. External areas will have the same criteria, with the deviation that external co-generation units will be assigned a must-run status subject to SPP review.

WIND REPOWERS AND CURTAILMENT PRICE

An automatic repower will be assumed for all wind units after 10 years of being in service and the projected production tax credits (PTC) will be applied. For solar and wind resources impacted by the Inflation Reduction Act (IRA), curtailment prices will reflect the PTC with the multiplier and one adder.

HURDLE RATES AND INTERCHANGE

Hurdle rates for all futures will be based upon the latest vendor data set. However, prior to and during the MEM benchmarking and initial MEM builds, SPP and ESWG will review the reasonableness of the latest vendor data set hurdle rates and respective interchange. SPP and ESWG may utilize, as appropriate, previous ITP MEMs in this review. This review may result in adjustments to the MEM hurdle rates and/or other economic model parameters that impact MEM interregional "economy-energy" transactions. Any ESWG-approved adjustments and MEM interchange results will be documented in the final ITP assessment report.

RESOURCE PLAN

RESOURCE PLAN POWERFLOW MODELING

The following parameters will guide how the resource plans, both internal and external, are modeled in all applicable models with regards to reactive settings, such as maximum and minimum volt-amps reactive (VAR) support and voltage schedule.

All resources included in the internal or external resource plans (excluding distributed generation, such as rooftop solar) 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 .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 resource. 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.

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. These parameters may be reviewed and adjusted to ensure erroneous system issues are not identified.

SOLAR, WIND, OR ENERGY STORAGE RESOURCES

The control mode for renewable and energy storage resources will be "+ or – Q limits based on WPF."[20] 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. These parameters may be reviewed and adjusted to ensure erroneous system issues are not identified.

[20] Wind power factor

ECONOMIC PROTOTYPES (ALL FUEL/RESOURCE TYPES)

Generator prototype parameters will be set using the Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies – EIA, Industrial combustion turbine (CT) will be the default. Members will be allowed to request an exception to the combustion turbine utilizing combined cycle (CC) single shaft or 95% Carbon Capture & Sequestration (CCS) Is from the EIA-Annual Energy Outlook (AEO). Exceptions must be approved by the ESWG. The table below details the characteristics of the approved prototypes in 2024 dollars for currency values.

GENERATION TYPE	DATA SOURCE	TECHNOLOGY TYPE	SIZE (MW)	TOTAL CAPITAL COST ($/KW)	VARIABLE O&M ($/MWH)	FIXED O&M ($/KW-YR)	HEAT RATE (BTU/KWH)
Combined Cycle (CC)	EIA AEO '23	95% CCS	543	$2,365.00	$5.05	$24.78	7,239
Combined Cycle (CC)	EIA AEO '23	Single Shaft	627	$921.00	$3.33	$15.51	6,226
Combustion Turbine (CT)	EIA AEO '23	Industrial	419	$836.00	$0.85	$6.87	9,142

Table 13: Generator Prototype Parameters

RESOURCE ACCREDITATION

SPP staff will complete a resource accreditation assessment[21] for all MEM scenarios to accredit resources for summer and winter PRM assessments.

SPP staff will categorize renewable resources into two categories, Tier 1 and Tier 2. Tier 1 resources include existing renewables with long-term firm transmission service or future renewables requested by a utility's integrated resource planning template response submitted to SPP during 2026 ITP and CPP Transition Study Assessment scope development. All remaining renewable resources will be considered Tier 2.

[21] These PRM and accreditation assessments are a proxy calculation for SPP's Resource Adequacy process not intended to replicate the final results or replace the process entirely.

Two Effective Load Carrying Capability (ELCC) percentage values for each season (summer and winter) will be used based upon SPP's latest ELCC study results. A total accreditation amount for each resource type in each scenario and season will be determined. Tier 1 resources will be given an accreditation value consistent with the ELCC percentage based on the Tier 1 amount. The total accreditation available from Tier 1 resources will be subtracted from the total accreditation value. Tier 2 resources will receive the remaining accreditation on a pro-rata basis. The following visual will replicate the process.

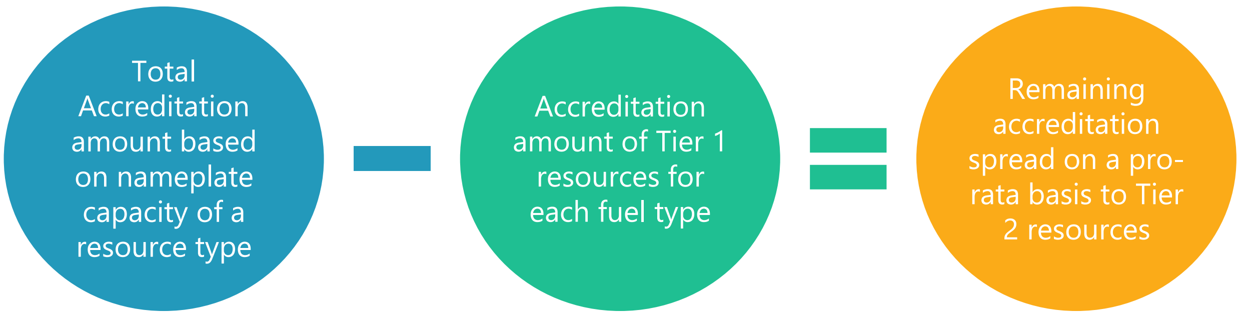

Figure 7: Accreditation

PLANNING RESERVE MARGIN VALUES

The PRM values utilized for the summer and winter seasons for study years 5, 10 and 20, will be from the latest approved LOLE study. If the study has not been approved, the PRM values utilized for the summer and winter seasons will be equivalent to those in the SPP governing documents.

NEW RESOURCE ALLOCATION AND ASSIGNMENT

Non-policy wind, solar, and storage resources requested via the IRP template will be assigned at 100% to the requesting utility. The specific resource assignments will be made in parallel with the siting milestone for the 2026 ITP and the CPP Transition Assessment.

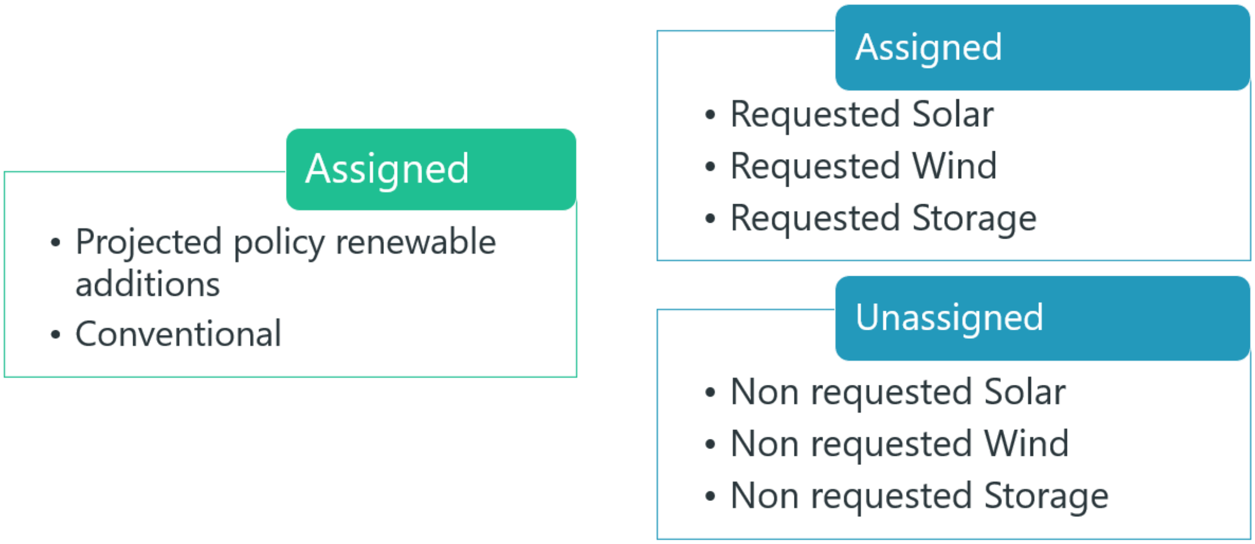

Figure 8: Resource Assignments

Policy additions will be met with 50% wind and 50% solar, based on the active, non-suspended GI queue requests.

Renewables will be allocated first based upon resource planning template responses to those utilities forecasting additions based on either the excess or deficit scenarios described in **Error! Reference source not found.** and **Error! Reference source not found.** below:

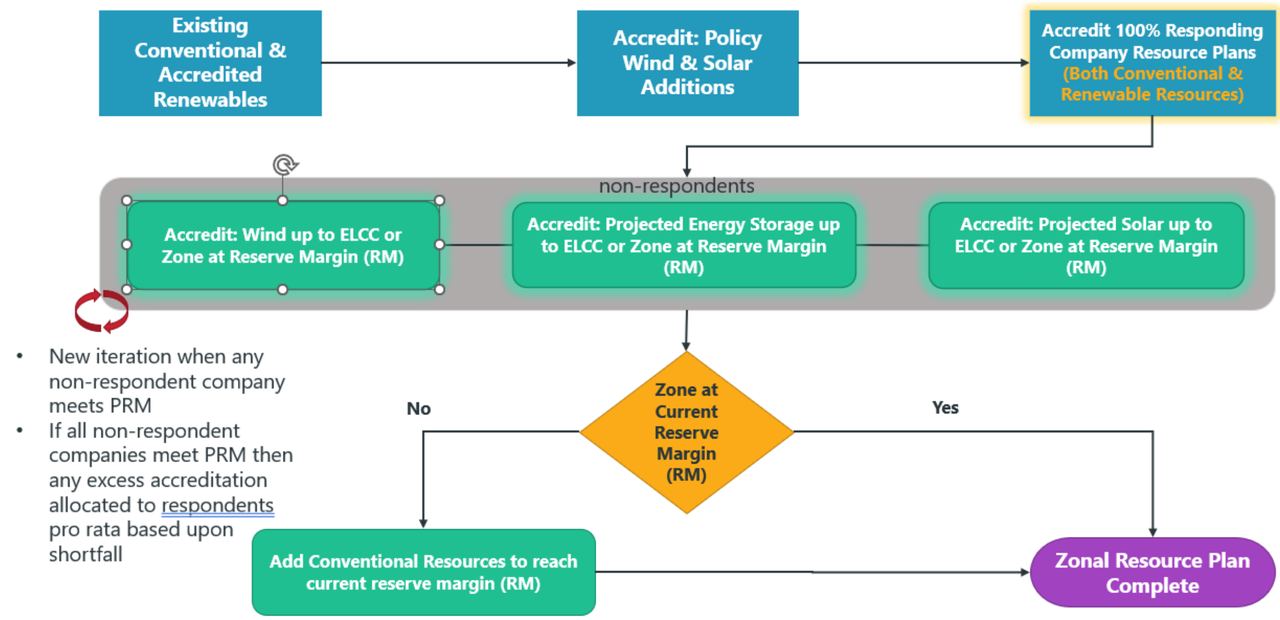

Figure 9: Resource Accreditation - Excess Scenario

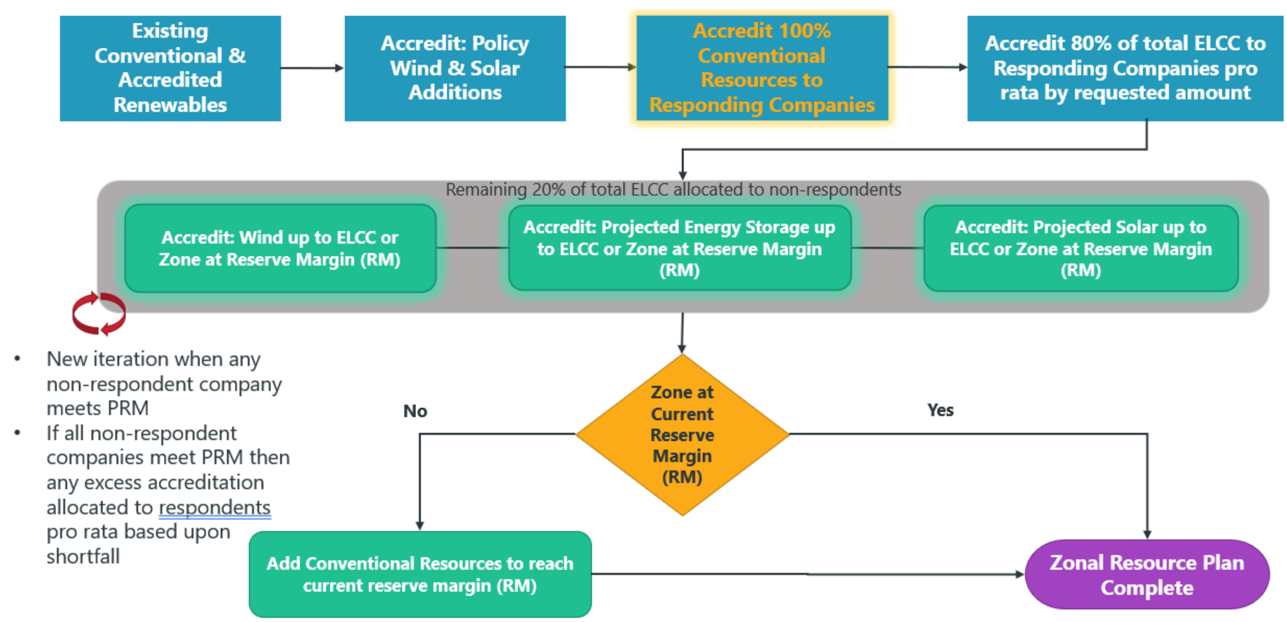

Figure 10: Resource Accreditation - Deficit Scenario

In the excess scenario, responding companies receive the full amount of renewable capacity requested in their resource planning template. The remaining ELCC will be allocated to non-responding companies pro rata (all fuel types) based upon shortfall, capped at PRM.

In the deficit scenario, responding companies will receive 80% of total ELCC on a pro rata basis by the requested amount. The remaining 20% of ELCC will be allocated to non-responding companies on a pro rata basis (by fuel type) based upon shortfall, capped at PRM.

STATE RENEWABLE PORTFOLIO STANDARDS

The following values will be used in accordance with Section 2.2.1.3 of the ITP Manual:

STATE	RPS TYPE	GENERATION TYPE	CAPACITY (MW) OR ENERGY (MWH) BASED	STATE-WIDE OR BY UTILITY	YEAR 5 %	YEAR 10 %	YEAR 20 %
Colorado	Mandate	Both	Energy	Utility	30%	30%	30%
Kansas	Goal	Both	Capacity	Utility	20%	20%	20%
Minnesota	Mandate	Both	Energy	Utility	25%	50%[22]	55%
Missouri	Mandate	Both	Energy	Utility	15%	15%	15%
New Mexico	Mandate	Both	Energy	Utility	40%	58%[23]	80%
North Dakota	Goal	Both	Energy	State	10%	10%	10%
Oklahoma	Goal	Both	Capacity	State	15%	15%	15%
South Dakota	Goal	Both	Energy	State	10%	10%	10%
Texas	Mandate	Both	Capacity	State	0%[24]	0%[19]	0%[19]

Table 14: ITP RPS by State

[22]Mandates are set after year 10, extrapolated values shown.

[23]Mandates are set after year 10, extrapolated values shown.

[24]Capacity goal of 1,965 MW of solar by August of 2025.

SECTION 3: NEEDS ASSESSMENT

The needs assessments will be performed as outlined in the ITP Manual, Section 4 (Needs Assessment), except as detailed below. The flowchart of the new process from Needs Assessment to Portfolio Consolidation begins in Figure 11 below and is continued in the **Error! Reference source not found.** in **Error! Reference source not found.**.

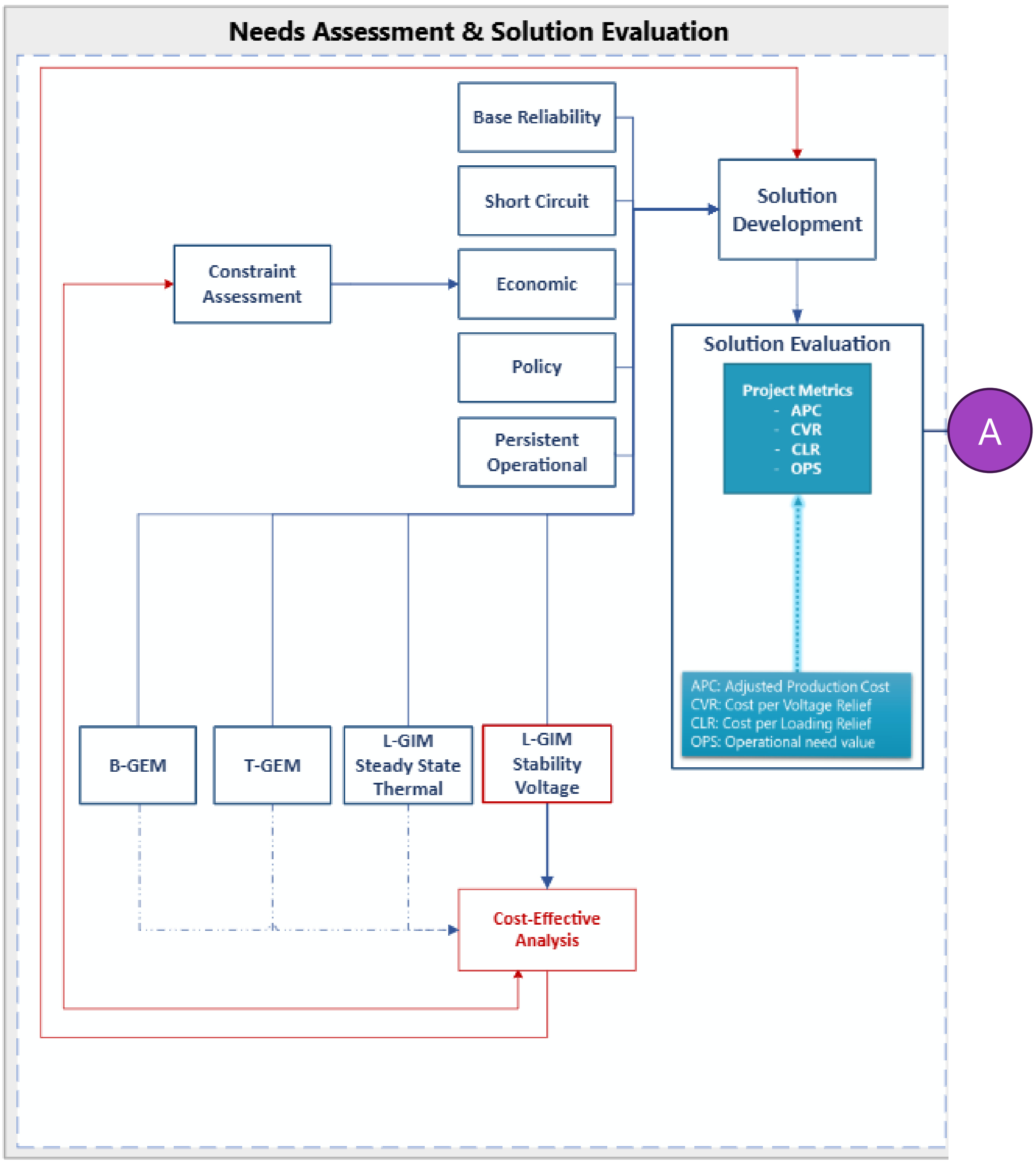

Figure 11: Needs Assessment flowchart

ECONOMIC NEEDS ASSESSMENT

The economic needs assessment of all futures and years will be performed consistent with the methodologies in Section 4.1 of the ITP Manual. The needs identified in the year 20 models will not be limited to the top 25 unique constraints, as outlined in the 20-Year Assessment Manual. This will ensure system congestion is assessed holistically and needs identified in earlier study years are carried forward through the study horizon, as appropriate.

RELIABILITY NEEDS ASSESSMENT

Reliability analysis utilizing year 20 models will be performed consistent with year 10 requirements unless otherwise detailed in this section.

GENERATION EXPANSION MODELS (GEM)

The contingency analysis for the Base Generation Expansion Model (B-GEM) and the Transmission Generation Expansion Model (T-GEM) will follow the base reliability needs assessment methodology as described in Section 4.2.1 of the ITP Manual, with the exclusion of NERC TPL-001 Category P3 planning events. Modifications to existing EHV contingency events—including P2.2, P2.3, P4.1 through P4.5, and P5 categories—and the development of new EHV proxy events (P4.1–P4.5) will be made for each modeled future year. These updates reflect changes in EHV substations and system topology driven by CPP planned generation additions, associated Generation Interconnection Agreements, and future resource expansion plans at CPP Planned Interconnection Locations.

The newly created proxy events are designed to represent expected adjustments necessary to modify existing P2.2, P2.3, and P5 events consistent with the updated system conditions. Both modified existing events and new proxy events will be named in accordance with the **SPP Contingency Naming Convention** as detailed in Appendix B of the 2025 SPP Annual Engineering Data Request Schedule.

Specifically, modified existing events addressing changes to EHV substations and line tapping will retain their original naming structure, with the addition of the substation point of interconnection bus number and the “LTAP” designation appended to Field 6: Event Description. Proxy events reflecting only line tapping modifications will similarly retain their naming conventions, appending “LTAPOnly” to Field 6. New proxy events that capture changes exclusively at EHV substations will preserve existing naming conventions, with the substation point of interconnection bus number appended to Field 6.

Where modifications are made solely for EHV substation changes, these proxy events will intentionally duplicate existing events. Both the original and duplicated events will be flagged as informational during preliminary violation reviews on a per-future-year basis, as outlined below.

For new P4.1 through P4.5 events associated with EHV substation changes, the following fields will be specified: Field 1—TPL-001-5 Table 1 Planning Event; Field 2—Nominal Voltage; Field 3—Transmission Owner; Field 6—Event Description (including substation point of interconnection bus number); and Field 7—Voltage Level Designation. Modified and new proxy events will utilize Field 8, the Special

Contingency Flag, set to "GEM/L-GIM EHV F#Y#" to clearly identify these events as applicable exclusively to the corresponding future and year models. This flag also aids in identifying event duplications and supports the review of thermal, voltage, and non-converged violations contingent upon interconnection requirement data specified elsewhere in this scope.

Except for the "LTAPOnly" modified events, all thermal, voltage, and non-converged violations associated with these proxy events will initially be classified as informational. However, during the preliminary violation review or the needs posting window, the Transmission Owner may designate any such violation as a valid non-informational need, based on interconnection requirement data, to support the integration of existing and planned generation in the ITP Base Reliability model, CPP planned generation additions, and future resource expansion plans. This classification facilitates the identification of solutions and supports portfolio development.

SPP will provide Transmission Owners with comprehensive lists of existing and planned generation reflected in the ITP Base Reliability models, CPP planned generation additions, and associated Generation Interconnection Agreements. These lists will include CPP Planned Interconnection Location points of interconnection, existing interconnection points for both current and planned generation, and responses from the ITP siting milestone and the Interconnection Requirement Information section of this scope. This information is intended to expedite Transmission Owner reviews and assist in distinguishing which events require inclusion in solution evaluations as non-informational needs.

Any needs resulting from GEM needs assessments will not be used to meet NERC TPL-001 or FAC-002 requirements. Any needs resulting from inter-DA T-GEM needs assessment will not be used to meet NRIS+ protection requirements.

LOCAL GENERATOR INTERCONNECTION MODELS (L-GIM)

In alignment with Table 6, thermal needs for the L-GIM steady-state analysis will be determined through standalone DC FCITC analyses performed on each resource plan unit by fuel type, following BP7250 fuel-based dispatch scenarios. This approach accounts for simultaneous dispatch of multiple resource plan units only when BP7250 electrically equivalent criteria require it. The contingency definitions applied will be consistent with those used in the base reliability needs assessment, except for the exclusion of NERC TPL-001 P3 planning events.

Modifications to existing EHV P2.2, P2.3, P4.1-P4.5, and P5 contingencies, along with the creation of new EHV P4.1-P4.5 proxy contingencies, will be developed on a per-future-per-year basis to incorporate changes in EHV substations and network topology. These changes result from CPP planned generation additions to the ITP base reliability models, incorporating Generation Interconnection Agreements and the siting of CPP Planned Interconnection Location points of interconnection, consistent with procedures documented for the GEM.

The Transfer Distribution Factor (TDF) impact for thermal overloads will follow BP7250 Section 4.2.2.2, except that ERIS cumulative impact criteria of 5% TDF and 20% of the constrained element's emergency rating will be omitted due to the standalone nature of this analysis for each resource plan unit.[25]

The L-GIM stability assessment will follow contingency analysis protocols outlined in the ITP Manual Section 4.2.1 and BP7250 Section 4.2.2, focusing on identification of voltage violations per BP7250 Sections 4.2.2.3 (Voltage Violations) and 4.2.2.1 (Non-converged events), with the exception of excluding NERC TPL-001 P3 events. In addition, consistent with EHV event modification for the GEM and L-GIM Steady State analysis, modifications and new proxy contingencies will be applied to HV and HV P2.2, P2.3, P4.1-P4.5, and P5 events similarly to the GEM, reflecting CPP planned generation additions. Non-converged blown-up violations will not initially be flagged as informational only by default unless the point of interconnection Transmission Owner identifies them as an invalid need during the preliminary review or posting window. Modified and new proxy events will utilize Field 8, the Special Contingency Flag, set to “GEM/L-GIM HV F#Y#” to clearly identify these events as applicable exclusively to the corresponding L-GIM Stability future and year models.

TDF impacts associated with voltage violations and non-converged events will adhere to BP7250 Sections 4.2.2.3 and 4.2.2.1 accordingly.

GEM AND L-GIM NEEDS CORRELATION WITH CONSTRAINT ASSESSMENT

Thermal violations identified through GEM and L-GIM needs assessments will be cross-referenced with thermal constraints found during the constraint assessment milestone. Thermal violations present in GEM or L-GIM but absent from the constraint assessment will be incorporated into the economic model event file.[26]

Single or multiple element transmission line contingencies causing severe voltage violations or non-converged conditions, indicative of potential system instability, will be correlated to thermal constraints from the constraint assessment. If no correlated violations are found in the economic model event file for GEM or L-GIM contingencies, proxy Power Transfer Distribution Factor (PTDF) flowgates will be included to represent these contingencies. These flowgates will be based on the elements or electrically similar elements involved in the contingency, oriented in the direction of system intact flow.

The ratings used to identify violations will apply 150% Surge Impedance Loading (SIL)[27] for single element contingencies, or the aggregated 150% SIL of all elements for multiple element

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[25] The L-GIM steady-state analysis is adopting the general approach used for ITP Site Screening of the Siting milestone, the Generator Outlet Facilities Analysis, and the SPP Hosting Capacity Tool.

[26] This includes constraints that are not identified by the constraint assessment process in total or by constraint assessment filtering criteria.

[27] Surge Impedance Loading formula: $SIL = (V^2) / Z$, where V is the line voltage and Z is the surge impedance (characteristic impedance) of the transmission line $Z = \sqrt{L/C}$.

contingencies, limited to the lesser of Rate A or the actual MW loading of the contingent element(s) where the violation was observed in GEM or L-GIM.

For single element transformer contingencies, a proxy PTDF flowgate will be added with a rating equal to 75% of Rate A, provided that 75% of Rate A is less than the actual MW loading of the contingency element.

SHORT CIRCUIT RATIO (SCR) SCREENING

The purpose of the short circuit ratio (SCR) screening analysis is to identify areas of the system that have low grid strength, which can be an indication of future stability needs. Indicators for stability needs may not be captured in reliability and economic assessments. This information will be used as an additional means of assessing reliability and economic transmission upgrades; however, this assessment alone will not identify new transmission upgrades for construction.

"System strength" refers to the voltage stiffness of an area or bus, meaning perturbations in the system near buses of concern will impact the bus voltage to some degree, depending on its strength. For example, a strong bus means a fault near the bus will cause a small voltage at the bus; conversely, a weak bus will experience a large voltage change. Weak areas are more susceptible to voltage oscillations, voltage instability or even voltage collapse.

The SCR metric measures the relative strength of the bus at the IBR point of interconnection (POI). An SCR of 3.0 or less is considered weak corresponding to reduced stability. More analysis is required for low system strength as the IBR may be susceptible to instability. To assess the SPP system's strength, an SCR check will be performed for each IBR point of interconnection. Further analysis for those buses areas with SCR less than studied further.

Screening at each candidate interconnection point is performed to evaluate system strength using the SCR, calculated with the equation:

$$\mathbf{SCR} = \frac{\mathbf{S_{SCMVA}}}{\mathbf{P_{RMW}}}$$

Where:

- $\mathbf{S_{SCMVA}}$: Maximum Available Short Circuit Power (MVA) before connection of the new resource
- $\mathbf{P_{RMW}}$: Real Power (MW) rating of resource(s) connected.

An SCR below a 3.0 will be considered during solution evaluation and development.

The S_{SCMVA} may be calculated by leveraging the formula shown below:

$$\mathbf{S_{SCMVA}} = \sqrt{\mathbf{3}} * \mathbf{V_{L-L}} * \mathbf{I_{SC}}$$

Where:

- **$V_{L\text{-}L}$:** Line to line voltage at the interconnection point
- **I_{SC}:** Three-phase short-circuit current at the interconnection point

SHORT-CIRCUIT CURRENT (I_{SC}) CALCULATION

- I_{SC} is determined through a short-circuit analysis using the latest stability models in PSS®E by applying a three-phase fault at each candidate interconnection point.
- Alternatively, I_{SC} may be calculated using the Thevenin Impedance Z_{TH} from PSS®E, with the formula:

$$\mathbf{I_{SC}} = \frac{\mathbf{V_{L-L}}}{\mathbf{Z_{TH}}}$$

The SCR will be calculated for existing generation at the interconnection point and updated to include the incremental change associated with prospective generating projects.

The Weighted Short Circuit Ratio (WSCR) will also be evaluated. This metric considers a high penetration of IBRs in a general area. Based on the electrical proximity of these IBRs, the WSCR determines an area SCR that can encompass anywhere from two to any number of IBRs. This metric consolidates the strength of the area into a single metric derived from the collective influence of the grouped IBRs. The WSCR is defined as:

$$\mathbf{WSCR} = \frac{\sum_{i=1}^{n} \mathbf{S_{SCMVA_i} * P_{RMW_i}}}{\left(\sum_{i=1}^{n} \mathbf{P_{RMW_i}}\right)^2}$$

If the final SCR or WSCR (current + prospective generation) is less than 3.0, an Electromagnetic Transient (EMT) analysis is deemed necessary to determine system stability.

SCR SCREENING CONTINGENCIES

The SCR will be performed on system intact conditions.

NON-CONVERGED CONTINGENCIES

Non-converged contingency analysis will follow the ITP Manual section 4.2.3 approach with consideration of BP7250 non-convergence analysis approach for B-GEM, T-GEM, and L-GIM stability models.

VIOLATION IDENTIFICATION AND FILTERING CRITERIA

Violations will be identified utilizing the following criteria for ACCC analysis.`

Description	Base Reliability	B-GEM	T-GEM	L-GIM Steady State	L-GIM Stability
Number of most severe violations for each facility per season per contingency type (single, non-single or Base Case)	Y5/Y10 - 10 Y20 – n/a	Y5/Y10 - 5 Y20 - 5	Y5/Y10 - 5 Y20 - 5	Y5/Y10 - 5 Y20 - 5	Y5/Y10 - 5 Y20 - 5
Minimum contingency case voltage change for range violations (current BR = 0.005)	Y5/Y10 - 0.009 pu Y20 – n/a	Y5/Y10 - 0.02 pu Y20 – 0.04 pu	Y5/Y10 - 0.02 pu Y20 – 0.04 pu	n/a	Y5/Y10 - 0.02 pu Y20 – 0.04 pu
Minimum contingency case flow change for overload report (current BR = 1 MW)	Y5/Y10 - 3 MW Y20 – n/a	Y5/Y10 - 5 MW Y20 – 10	Y5/Y10 - 5 MW Y20 – 10	Y5/Y10 - 5 MW Y20 – 10	n/a
Minimum contingency case percentage loading increase for overload reports (current BR = .5%)	Y5/Y10 - 0.5% Y20 – n/a	Y5/Y10 - 1% Y20 - 2%	Y5/Y10 - 1% Y20 - 2%	Y5/Y10 - 1% Y20 - 2%	n/a
Bus mismatch tolerance (MVA) (current BR = 1 MVA)	Y5/Y10 - 3.0 MVA Y20 – n/a	Y5/Y10 - 3.0 MVA Y20 – 5.0	Y5/Y10 - 3.0 MVA Y20 - 5.0	Y5/Y10 - N/A MVA Y20 - N/A	Y5/Y10 - 3.0 MVA Y20 – 5.0
System mismatch tolerance (MVA) (current BR = 10 MVA)	Y5/Y10 - 10 MVA Y20 – n/a	Y5/Y10 - 10 MVA Y20 - 20	Y5/Y10 - 10 MVA Y20 - 20	Y5/Y10 - 10 MVA Y20 - 20	Y5/Y10 - 10 MVA Y20 - 20

Figure 12: Violation Identification and Filtering Criteria

Resulting violations will be filtered after excluding invalid and informational violations to determine a list of valid non-informational violations that will be included in the needs assessment, consistent with ITP methodologies. All valid informational violations related to modified and new GEM and L-GIM events that did or did not receive feedback during the preliminary violations review will be included in the needs assessment to allow for further review as needed during the DPP window in conjunction with the gathering Interconnection Requirement Information.

INTERCONNECTION REQUIREMENT INFORMATION

Immediately after the conclusion of the siting milestone approval, SPP will request additional interconnection requirement information from applicable Transmission Owners for CPP Planned

Interconnection Locations for posting as pre-screening information for the 2028 CPP10 generation connection process, to facilitate the review of modified or new proxy planning events as described in the GEM and L-GIM reliability needs section, inform changes to approved site infeasibility designations, and inform as necessary transmission plan recommendations.

SPP will supply Transmission Owners for each Planned Interconnection Location point of interconnection site a list of existing, planned generation in the ITP BR, CPP planned generation additions to the ITP base reliability models with Generation Interconnection Agreements grouped by the dedicated or shared interconnection gen lead for each, and the additional approved stand-alone and co-located sites. The listing will include the interconnection feasibility information received from the ITP siting milestone. The applicable Transmission Owners will identify the number of cost effective/commercially viable gen lead bus breaker connections needed to connect the CPP Planned Interconnection Location sites for each nodal point of interconnection consistent with Transmission Owner Interconnection Requirements and standards.

FACILITY RATING DATA

Comprehensive facility rating data will be required to develop least cost solutions in support of L-GIM portfolio development and consideration as cost-effective alternatives for development of other portfolios. To expedite the development of these least cost and cost-effective alternatives, Transmission Owners shall supply readily available facility rating databases and data or facility rating data sheets to include all monitored elements identified during the preliminary violation review for use by SPP staff and consulting agents. In instances where the Transmission Owner do not supply the requested facility data, transmission owners can expect comprehensive generation interconnection process data requests as schedules allow or defaulting to line rebuilds and transformer replacements for project alternative comparisons to new lines and transformation.

LIMITED OPERATION INFORMATION

To support the Invest, Connect, and Manage policy direction of the Consolidated Planning Process, thermal violations identified in the L-GIM needs assessment will be categorized as:

- Thermal constraints with and without a Market Operations Redispatch solution based on:
  - whether or not the contingency is consistent with the normal operation of the SPP Integrated Marketplace and,
  - there are no directly related soft constraint[28] violations identified in the MEM
- A voltage and non-converged constraint that is proxied by thermal constraints with and without a Market Operations Redispatch solution based on:

[28] Soft Constraints are defined as the “soft" penalties representing the cost in $/MW to violate the particular constraint. The constraints include line flow constraints, pool load balance constraints, cost of emergency energy purchase at a bus, and operating reserve constraints.

  - whether or not the contingency is consistent with the normal operation of the SPP Integrated Marketplace, and
  - there are no directly related soft constraint violations identified in the MEM
- A voltage and non-converged constraint that is not proxied by thermal constraints and has a proxy PTDF flowgate included with and without a Market Operations Redispatch solution based on:
  - whether or not the contingency is consistent with the normal operation of the SPP Integrated Marketplace and,
  - there are no directly related soft constraint violations identified in the MEM

This information will be utilized to recommend must fix needs and needs that can be managed by the SPP Integrated Marketplace to allow planned resource plan sites prospective in-service dates prior to construction of approved transmission plans.

AFFECTED SYSTEM INFORMATION

The analysis performed during the L-GIM needs assessment will monitor first-tier affected systems to include AECI, CIPCO, Minnkota, and MISO North and South, consistent with Generation interconnection Affected System studies.[29] MISO North monitoring will be limited by the expanded scope methodology defined by the SPP-MISO Joint Targeted Interconnection Queue Study (JTIQ). This information will be utilized to identify planned resource plan sites and respective affected system impacts that can be subject to future affected system studies, inform portfolio development, inform seams policy development, and be monitored as part of the final reliability assessment to demonstrate any affected system impacts mitigation by the final portfolio approved for construction.

[29] For more information on Affected Systems coordination, refer to SPP BP7250, Section 4.6, and Attachment V of the SPP Tariff, Section 3.6.

SECTION 4: SOLUTION EVALUATION

The methodologies outlined in Section 5 of the ITP Manual will serve as the basis for all analysis applicable to the Solution Development and Evaluation milestones. Exceptions and qualifications are outlined below.

PERSISTENT ECONOMIC OPERATIONAL SOLUTION EVALUATIONS

FLOWGATES

SPP will perform the persistent operational needs assessment prior to the 2026 Combined Assessment benchmarking milestone for further investigation and validation of the year 2 economic models. As part of the 2026 Combined Assessment, SPP will make a recommendation to working groups on whether or not to address persistent operational needs according to ITP Manual section 4.4.

MANUAL COMMITMENT OF GENERATORS

Some transmission system issues require the manual commitment of generation by SPP in the Integrated Marketplace to provide relief on the system. The make-whole payments avoided when a proposed solution is included in the model will be considered in the solution's benefit. Each solution's one-year benefit-to-cost (B/C) ratio and its ability to reduce or eliminate the need for manual commitments will be considered during project selection.

ECONOMIC SOLUTION EVALUATION

The methodologies outlined Section 5.3.1 of the ITP Manual will be utilized to perform economic solution evaluation. For analysis of project performance in the 20-Year economic models, these methodologies will supersede the requirements outlined in the Solution Development section of the 20-Year Assessment Manual.

L-GIM RELIABILITY SOLUTION EVALUATION

SPP Business Practice 7250 least cost methodology will be used to develop solutions to address L-GIM needs. All solutions[30] will be evaluated against L-GIM reliability needs to calculate a loading relief for each solution and mitigated need.

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

SECTION 5: PORTFOLIO DEVELOPMENT

The methodologies and criteria outlined in Section 6.1 of the ITP Manual will serve as the basis for portfolio development. Any additional portfolio development criteria, exceptions or qualifications required to meet the holistic objectives of this assessment are listed in this section.

The ITP portfolio development process flow will be modified to accommodate the additional analysis included in this assessment as shown in **Error! Reference source not found.**

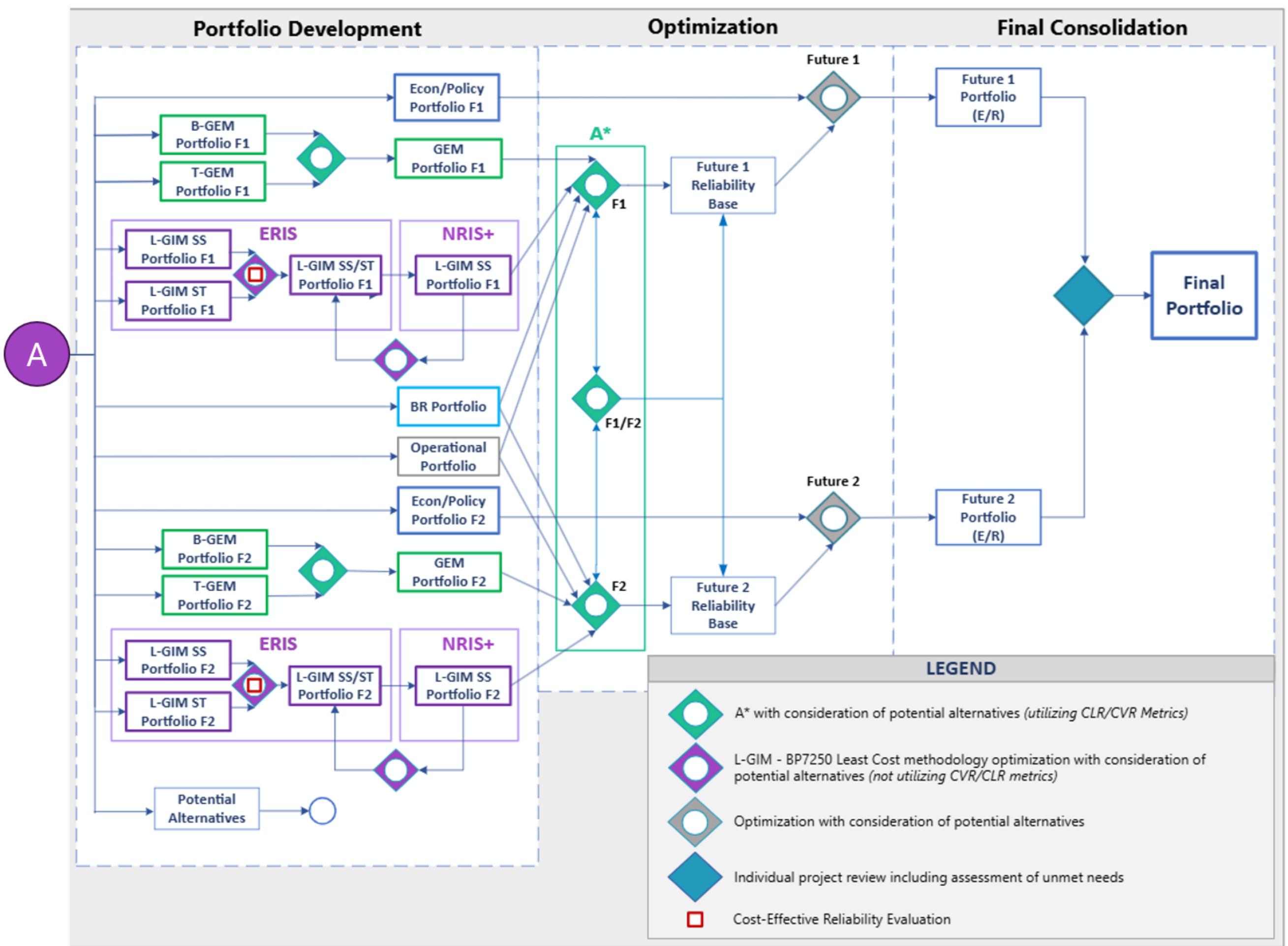

Figure 13: Portfolio Development Flowchart

RELIABILITY PORTFOLIO DEVELOPMENT

In addition to BR and operational portfolios, draft GEM and L-GIM portfolios will be developed for each future as shown in **Error! Reference source not found.**. The reliability portfolio development methodologies outlined in Section 6.1.2 of the ITP Manual will apply to the GEM and L-GIM models, except as outlined below.

L-GIM PORTFOLIO DEVELOPMENT

L-GIM ERIS steady-state and stability proxy portfolios will initially be developed separately for this assessment. While transient stability analysis will not be performed and current ITP tools will be able to optimize solutions to address both need types, certain identified needs will follow a cost-effective reliability evaluation based on the cost of the required transmission solution as described in the portfolio optimization section. A least cost approach will generally be utilized instead of the cost-effective CVR/CLR metrics to adhere to generator interconnection principles for resolving issues.

If issues arise utilizing the ITP procedures for reliability portfolio development, the process outlined in section 4.2.3 of BP7250 (GI Manual) may be leveraged to produce an optimized L-GIM portfolio.

L-GIM NRIS steady-state portfolio will be developed, assuming the optimized L-GIM ERIS portfolio. If incremental projects are identified for the L-GIM NRIS steady-state that can avoid L-GIM ERIS portfolio projects, the L-GIM ERIS portfolio project will be replaced by the incremental project and identified as L-GIM ERIS portfolio project.

ECONOMIC PORTFOLIO DEVELOPMENT

The methodologies outlined in the ITP Manual, Sections 6.1.1, will be utilized to develop economic portfolios. These methodologies will augment or supersede the requirements in the 20-Year Assessment Manual for the purpose of meeting 20-Year Assessment requirements.

USAGE OF 20-YEAR ADJUSTED PRODUCTION COST (APC) DATAPOINT

The economic portfolio development processes will consider the use of each of the available model years to meet near- and long-term objectives of this combined assessment. Development of a holistic portfolio that can meet needs in the 20-year horizon will consider additional datapoints and voltage classes excluded from consideration in the 20-Year Assessment Manual and a year 20 datapoint not contemplated in the ITP Manual.

It may be necessary to develop a set of portfolios that focus on a medium- and/or long-term horizon. Data will be available to assess the economic benefit of transmission upgrades in each of the model years and perform present value benefit calculations with and without a year 20 datapoint on a 40-year horizon. In addition to addressing potential technical challenges, it may be desirable to develop portfolios to address transmission needs in different time horizons to delineate between near- and long-term portfolios.

PORTFOLIO OPTIMIZATION

RELIABILITY PORTFOLIO OPTIMIZATION (FUTURE-SPECIFIC)

BR, Operational, GEM, and L-GIM portfolios will be optimized to create a holistic reliability portfolio per future.

RELIABILITY AND ECONOMIC OPTIMIZATION (FUTURE-SPECIFIC)

Select reliability needs for the L-GIM will be evaluated as a reliability and economic need during or after the needs assessment to ensure proper evaluation of system needs and solutions.

COST EFFECTIVE ANALYSIS FOR L-GIM STABILITY ISSUES

The L-GIM stability model is designed to cluster the Resource Plan into subregional groups based on electrical impacts[31] to identify voltage violations and proxy stability issues. In both historical and current applications of BP7250, this clustering approach supports the evaluation of localized reliability impacts while adequately reflecting the expected dispatch of Prior-Queued Generation, as well as Legacy and Non-Legacy ITP Base Reliability Generation. This is achieved through BP7250's fuel-based dispatch methodology, which utilizes a region-wide sinking approach across the entire SPP footprint.

While this sinking methodology reflects a demand for resources from the regional market, it introduces a significant analytical limitation. The combination of subregional clustering and a region-wide sink can overstate inter-subregional transfer flows, particularly at subregional boundaries, that can result from the volume of generation being analyzed in any one sub-region. As a result, the modeled reliability needs often exceed those identified through the ITP Base Reliability and Aggregate Transmission Service Studies for existing and planned resources, as well as economic transfer flows represented in the ITP MEM. These overstated transfers are also expected to exceed the requirements established through the TGEM process for both inter- and intra-subregional transfers.

To address these limitations within the L-GIM stability model dispatch and the BP7250-based analysis, a refined reliability assessment process has been developed. This process—outlined in the accompanying flowchart—ensures consistency, transparency, and non-discriminatory treatment of all resources evaluated in this study, as well as in ongoing CPP evaluations of generation interconnection requests, whether considered planned or unplanned. The process also incorporates a correlation between identified L-GIM needs and constraint assessment results to support economic model analysis and to capture customer Limited Operation information on subregional export limitations.

[31] As generally shown in Figure 4, consistent with BP7250.

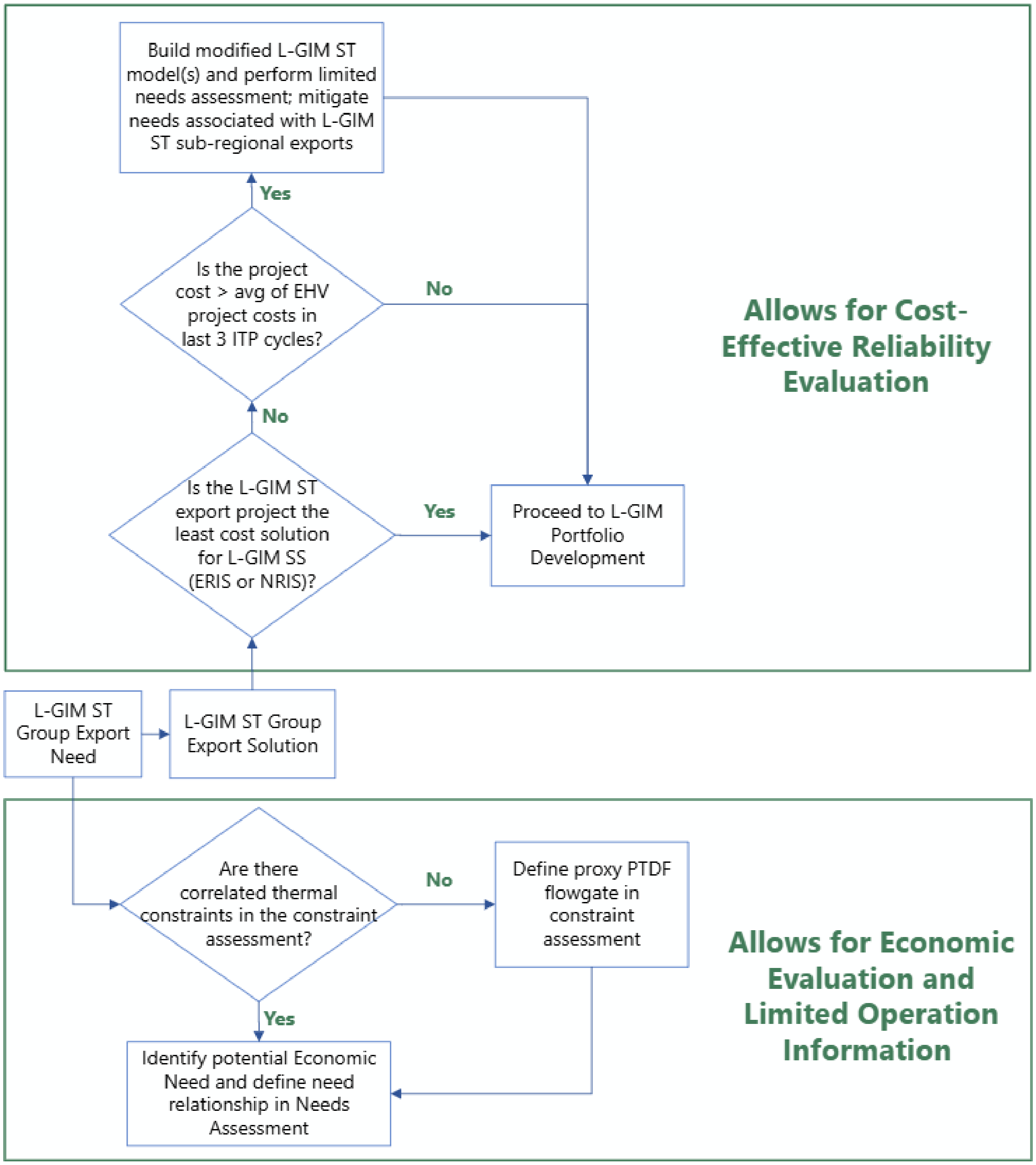

Figure 14: Cost Effective Reliability Evaluation

This process is utilized to identify alternative solutions to address subregional boundary issues at more reasonable subregional export levels. As part of this process, a reliability-based solution cost threshold is established to trigger further evaluation of the overstated transfers to identify more cost-effective transmission expansion options. This threshold is based on the average cost of Extra-High Voltage (EHV) projects greater than $20 million that were approved for construction in the three most recent ITP assessments. If a proposed reliability-based solution to address violations identified in the L-GIM analysis exceeds this cost threshold and is not identified as the least-cost solution in the L-GIM ERIS and NRIS steady-state analysis, an adjusted evaluation is initiated.

This adjusted evaluation involves modifying the relevant power flow models by reducing the subregional export level(s) to a more expected export amount. This export amount is defined by setting the sum of the subregional generation to the greater of:

1. The subregional generation accreditation plus the planning reserve margin (PRM), as defined in the PRM Values section, or

2. The sum of the subregional generation accreditation, the PRM, and all subregional Future Resource Plan capacity (by future and year) at forecasted nameplate levels, including BP7250 Electrically Equivalent exceptions for Prior-Queued Generation and Non-Legacy ITP Base Reliability Generation.

To achieve the reduced export level in the models, dispatch adjustments are made by proportionally scaling down Prior-Queued, Legacy, and Non-Legacy ITP Base Reliability Generation within the sub-region, excluding Electrically Equivalent exceptions and any units designated as must-run. Concurrently, dispatch levels of out-of-group Legacy and Non-Legacy ITP Base Reliability Generation are proportionally increased, excluding any must-run units.

Using these adjusted models, a limited reassessment is performed. This includes:

- Reviewing the export-related and out-of-group voltage and proxy stability criteria violations (as non-converged events) that initially drove the higher-than-average reliability-based solution cost;

- Identifying any remaining export-related and out-of-group reliability needs and associated solutions; and

- Re-evaluating shared system events that intersect with any subregional Future Resource Plan point of interconnection at the adjusted export level. This re-evaluation will include, at a minimum, capacity modeled at forecasted nameplate levels with inclusion of BP7250 Electrically Equivalent exceptions for Prior-Queued and Non-Legacy ITP Base Reliability Generation.

The objective of this effort is to define a set of needs driven by expected export levels and to identify more cost-effective transmission solutions. These refined solutions will be considered for inclusion in the comprehensive CPP Portfolio development process.

PORTFOLIO CONSOLIDATION

Future-specific portfolios will be consolidated into a single set of projects to determine a recommended plan. The methodology by which this consolidation will occur is based on individual project performance. A systematic approach to evaluate each project's merits and an SPP-developed narrative of each project's drivers will guide the decision for inclusion in the recommended plan.

Projects with multiple need drivers will be evaluated through all applicable portfolio consolidation approaches, as needed. SPP may use engineering judgement or other analysis to support or oppose the results of the systematic approaches or criteria described in the sections below. SPP will bring consolidation results and a recommendation for all projects selected for a future-specific portfolio to the ESWG and TWG for review and feedback.

Three different scenarios could occur during the consolidation of the future-specific portfolios into a recommended plan; these are described in the next section.

OVERVIEW OF CONSOLIDATION SCENARIOS

SCENARIO 1

Projects selected for inclusion in both futures are considered for evaluation in consolidation scenario 1. Scenario 1 projects address the same or similar needs in both futures and will be included in the final recommended portfolio.[32]

SCENARIO 2

Different projects selected for each future that address the same or similar needs in both futures are considered for inclusion in the final recommended plan through evaluation under consolidation scenario 2. Economic projects applicable to consolidation scenario 2 will be evaluated using multiple considerations through a scorecard methodology detailed in Economic Portfolio Consolidation. Reliability projects applicable to consolidation scenario 2 will be evaluated similarly to reliability portfolio development methodologies, as described in Reliability Portfolio Consolidation.

SCENARIO 3

Projects selected for inclusion in only one future are considered for inclusion in the final recommended plan through evaluation under consolidation scenario 3. Economic projects applicable to consolidation scenario 3 will be evaluated using the same considerations as consolidation scenario 2 but a different methodology detailed in the Economic Portfolio Consolidation section. Reliability projects applicable to consolidation scenario 3 will be evaluated using a set of mutually inclusive criteria detailed in the Reliability Portfolio Consolidation section.

ECONOMIC PORTFOLIO CONSOLIDATION

Economic projects applicable to scenarios two and three will be given a score based on the point system detailed in Table 15. Each project will be awarded points based on its performance or ability to meet six different considerations, up to 100 total possible.

No.	Considerations	Points Possible	Threshold
1	40-year (1-year) APC B/C in Selected Future	50	1.0 (0.9)
	40-year (1-year) APC B/C in Opposite Future		0.8 (0.7)
	40-year (1-year) APC Net Benefit in Selected Future ($M)		N/A

[32] Subject to the use of engineering judgment described above.

No.	Considerations	Points Possible	Threshold
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		N/A
2	Congestion Relieved in Selected Future (by need(s), all years)	10	N/A
	Congestion Relieved in Opposite Future (by need(s), all years)	10	N/A
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	>0
4	New EHV	7.5	Y/N
5	Mitigate Non-Thermal or Resiliency Issues	7.5	Y/N
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)[33]	5	Y/N
	Total Points Possible	**100**	

Table 15: Economic Consolidation Considerations Scoring Table

For two projects (P1 and P2) applicable to scenario two, points for consideration one will be calculated as follows:

1. Test B/C thresholds in opposite future
    - If project has less than 0.8 40-year B/C in opposite future, zero points will be awarded
    - If project meets 0.8 40-year B/C threshold in opposite future, continue calculations
    - If project has less than 0.7 1-year B/C in all years of opposite future, zero points will be awarded
    - If neither of the above conditions are met, continue calculations
2. Calculate 40-year net adjusted production cost (APC) benefits
    - Net APC benefit$_{P1,AVG}$
    - Net APC benefit$_{P2,AVG}$
    - Net APC benefit$_{Max}$ = Maximum(Net APC benefit$_{P1,AVG}$,Net APC benefit$_{P2,AVG}$)
3. Calculate points awarded
    - $Points\ awarded_{P1,\%} = 50 \times \frac{Net\ APC\ benefit_{P1,AVG}}{Net\ APC\ benefit_{Max}}$
    - $Points\ awarded_{P2,\%} = 50 \times \frac{Net\ APC\ benefit_{P2,AVG}}{Net\ APC\ benefit_{Max}}$

[33] Similar termination points determined if they are located no more than 1 station (sub-station, switching station, or other station as identified in the SPP Model) away or within 15 linear miles as noted in SPP BP 7650

For individual projects (P1) applicable to scenario three, points for consideration one will be calculated as follows:

1. Test B/C threshold in opposite future
   - If project has less than 0.8 40-year B/C in opposite future, zero points will be awarded
   - If project has less than 0.7 1-year B/C in all years of opposite future, zero points will be awarded
   - If project has at least 1.0 40-year B/C in opposite future, 50 points will be awarded
   - If project meets 0.8 40-year B/C threshold in opposite future, but is less than 1.0, continue calculations
   - If none of the above conditions are met, continue calculations
2. Calculate net APC benefits
   - Net APC benefit$_{P1,AVG}$
   - Net APC benefit$_{P1',AVG}$ = Net APC benefit$_{P1,AVE}$ with 1.0 40-year B/C in opposite future
3. Calculate points awarded
   - $Points\ awarded_{P1,\%} = 50 \times \frac{Net\ APC\ benefit_{P1,AVG}}{Net\ APC\ benefit_{P1',AVG}}$

Points for consideration two will be calculated as the percentage of total congestion relieved on the needs addressed by the project, multiplied by the points possible.

$$Points\ awarded = 10 \times \%\ Congestion\ relieved_{F1,addressed\ needs} + 10 \times \%\ Congestion\ relieved_{F2,addressed\ needs}$$

Points for consideration three will be calculated based on the severity of an operational issue that the project is expected to address, as a percentage of the operational needs criteria[34] multiplied by the points possible, up to 10.

$$Points\ awarded = \left(\frac{\$\ of\ congestion\ cost_{24\ months}}{\$10M}\right) \times 10$$

OR

$$Points\ awarded = \left(\frac{Hours\ of\ system\ reconfiguration_{12\ months}}{X\%^{35} \times 8{,}760}\right) \times 10$$

[34] Flowgate congestion cost totaling more than $10M over the last 24 months or system reconfiguration through an agreed-upon operating guide implemented 25 percent of year.

[35] X equals 25 percent for operational thermal issues. X equals 10 percent for operational voltage issues.

All points possible for considerations four, five, and six will be awarded if the project meets the description of the consideration.

For projects applicable to scenario two, the project with the highest score will be considered the favorable project based on the systematic approach. Projects applicable to scenario three with a total score of 70 or greater will be considered for the final recommended plan.

RELIABILITY PORTFOLIO CONSOLIDATION

Reliability projects applicable to scenario two will be consolidated following the approach of the optimization milestone, utilizing the same criteria to develop each future’s reliability portfolio. This will allow needs across both futures to be considered and allow for project alternatives to be considered when determining the most optimal solution.

Reliability projects applicable to scenario three will be evaluated according to the following criteria to determine if those projects will be included in the final consolidated portfolio:

1. Projects driven by Year 5

   This criterion assumes that either of the futures’ drivers included in Year 5 can reasonably be expected to occur.

2. Terminal equipment upgrades

   Low cost solutions able to provide additional transmission capacity will be included.

3. Rebuild of an existing facility

   This criterion considers the rebuild of a facility below minimum design standards. This also accounts for potential aging infrastructure considerations.

4. Average of loading/voltage severity across futures

   These criteria will consider the most severe violation or highest loading of needs across all years when comparing common monitored elements in each future as follows:

   a. Thermal: Average of thermal loading across futures greater than 90%

   b. Voltage: Average of per unit voltage across futures less than 92% on the low end and greater than 103% on the high end

   Projects addressing needs that meet either of these criteria will be included.

5. Load-driven projects

   This criterion will be based on the size and level of certainty for the expected load driving the project. This will generally be applicable to large load additions identified during scoping development.

6. Future generation-driven projects (L-GIM only)

   This criterion is based on the level of impact of individual generators. If 10% of the generators within a GI group impact a need by greater than a 3% TDF, the project resolving the need will be included.

7. APC benefit

   Reliability projects resolving reliability needs in either future and meeting a minimum 40-year 0.8 B/C threshold will be included.

These criteria are mutually inclusive and will likely be assessed considering increasing complexity of the criteria until one is met.

A redundancy check will be performed to avoid overlap between the results of reliability consolidation scenarios 2 and 3.

PROJECT STAGING

Projects will be staged based on the criteria in Section 6.3 of the ITP Manual, except as described in this section. The project staging milestone is intended to define the required in-service date of a transmission upgrade and to support recommendation of projects for construction that meet historical precedence of NTC issuance criteria of the SPP Board. Traditionally, the SPP Board does not issue NTCs for projects that do not require financial expenditure within the first four years from approval.

To meet proactive planning objectives, preference will be given to long-term transmission solutions with consideration of short-term mitigations. This could result in projects of longer-term value and less short-term benefit being recommended that may not meet traditional staging criteria for a project to be recommended for construction. This should be considered in determining both incremental upgrades of a project that could be staged in the near-term and projects that may warrant discussion to reconsider the four-year financial expenditure precedent.

FINAL RELIABILITY ASSESSMENT

To ensure reliability of the recommended transmission plan, a contingency analysis will be performed with the final consolidated portfolio included in the base model set(s). At a minimum, this analysis will be performed on the Base Reliability and Base Generator Expansion model sets. Results of the final reliability assessment may require modification or addition to the final consolidated portfolio.

Throughout the solution evaluation and portfolio development milestones targeted analysis will be performed to identify any potential violations caused by proposed transmission projects, but there will not be a comprehensive evaluation of contingencies, models, or aggregate impact of the final portfolio of transmission projects until the final reliability assessment.

Additional analysis may be performed utilizing T-GEM and L-GIM model sets to ensure a more comprehensive evaluation of the impact of the final consolidated portfolio. This will be considered prior to the final reliability assessment milestone and dependent on the completeness of interim analysis, expectation of potential impacts of the specific transmission upgrades, and uniqueness of transmission needs or projects driven by the other model sets.

SECTION 6: INFORMATIONAL ANALYSIS

BENEFIT METRICS

Benefit metrics will be calculated consistent with Section 7.1 of the ITP Manual. The metrics will incorporate the 20th year datapoint where applicable.

SENSITIVITY ANALYSIS

Sensitivities will be conducted on the final consolidated portfolio in both futures to measure the flexibility of the portfolio with respect to the uncertainties of certain assumptions. Economic analysis will be performed for the sensitivities below:

- High and low natural gas prices
- High and low demand levels
- High and low solar and wind levels

Additional sensitivities will be determined via stakeholder survey leading up to this analysis and will be documented in the CPP Combined assessment report.

RATE IMPACTS

The net impact of the recommended transmission plan on a typical residential customer within the SPP Region will be assessed, on a $/kWh basis both with and without GRID-C contributions from the Resource Plan. Base Plan Funding projections for the NRIS+ portion of the Resource Plan will not be considered

DATAPOINTS TO SUPPORT GRID-C POLICY

In order to support calculation of the GRID for upcoming CPP studies, data from different milestones needs to be gathered or calculated and summarized. This includes, but may not be limited to the following:

- Max capacity of existing generators
- Resource plan generators (grouped by subregional pricing zone)
  - Maximum capacity
  - Assumed accreditation
  - Annual energy output
  - GSFs on transmission elements (base case monitored)

        - All EHV for the footprint
        - HV by subregional pricing zone
- Final portfolio (consolidated) project costs
- L-GIM-specific upgrades
    - By service type (ERIS/NRIS)
    - By subregional pricing zone
    - Upgrades unable to be optimized

SECTION 7: SCHEDULE

The 2026 ITP assessment and CPP Transition Assessment began in July 2024 and will be completed by October 2026.[36] Figure 15 and **Error! Reference source not found.** detail the study timeline.

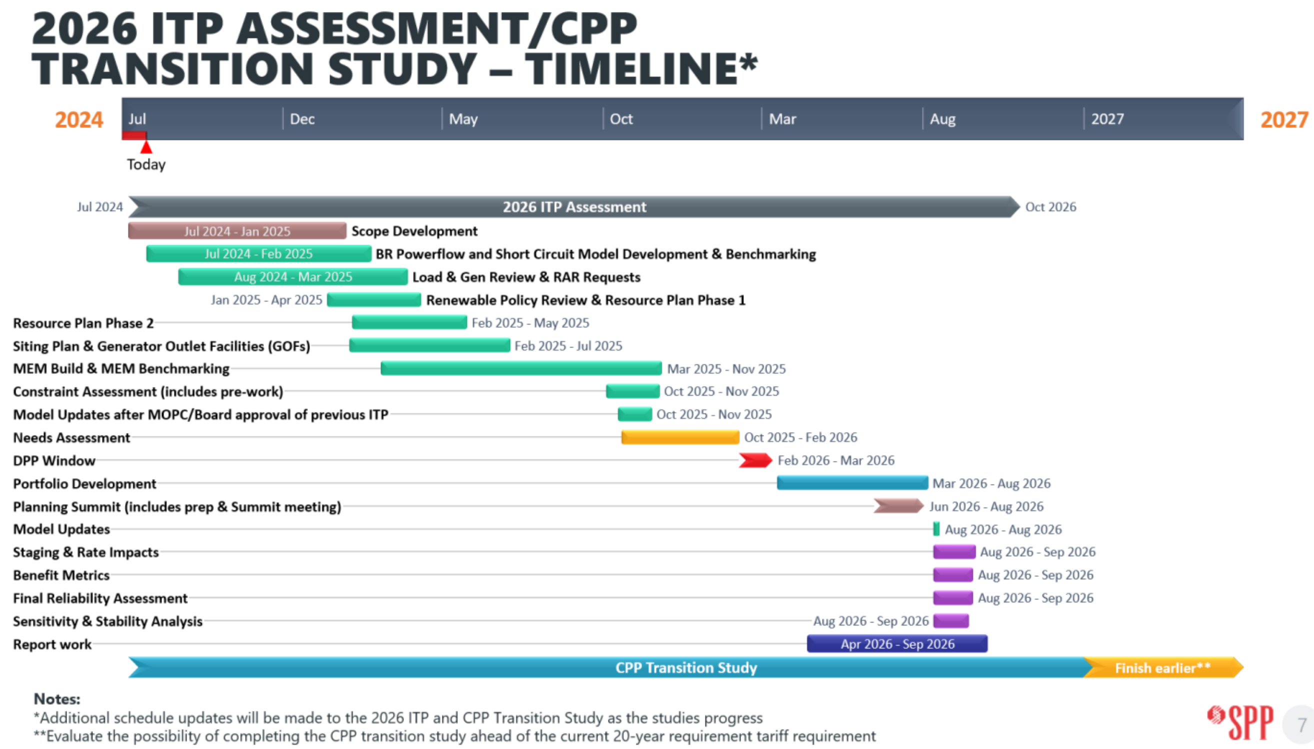

Figure 15: 2026 ITP and the CPP Transition Assessment Timeline

MILESTONE NAME	GROUP(S) TO REVIEW/ENDORSE	START DATE	COMPLETION DATE
Scope Development – Phase 1 *(up to needs assessment)*	ESWG, TWG, MOPC, SPC, CPPTF	Jul 2024	Jan 2025
Scope Development (final)	ESWG, TWG, MOPC, CPPTF	Dec 2024	Jul 2025
Base Reliability Powerflow & Short Circuit Model Development	TWG	Jul 2024	Feb 2025
Load and Generation Review	ESWG, TWG, MDAG	Aug 2024	Mar 2025
Renewable Policy Review	ESWG	Mar 2025	Apr 2025
Renewable Resource Plan (RP1)	ESWG, CAWG	Mar 2025	May 2025
Conventional Resource Plan (RP2)	ESWG, CPPTF	Mar 2025	May 2025

[36] Dates are subject to change.

MILESTONE NAME	GROUP(S) TO REVIEW/ENDORSE	START DATE	COMPLETION DATE
Siting Plan & Generator Outlet Facilities (GOFs)	ESWG, CPPTF	Jan 2025	Jul 2025
Powerflow Model Development	TWG	Mar 2025	Nov 2025
Short Circuit Model Development	TWG	Mar 2025	Nov 2025
Economic Model Development	ESWG	Mar 2025	Nov 2025
Model Benchmarking	ESWG, TWG	Jun 2025	Aug 2025
Model Updates after 2025 ITP Approval MOPC/Board (NTC/Re-evaluations)	TWG	Oct 2025	Nov 2025
Constraint Assessment	TWG	Sept 2025	Nov 2025
Needs Assessments	ESWG, TWG	Oct 2025	Feb 2026
Detailed Project Proposal (DPP) Window	ESWG, TWG	Feb 2026	Mar 2026
Solutions Development	ESWG, TWG	Feb 2026	Apr 2026
Project Grouping	ESWG, TWG	Apr 2026	May 2026
Study Cost Estimates		May 2026	July 2026
Summit		July 2026	July 2026
Final Portfolio Development	ESWG, TWG	July 2026	Aug 2026
Portfolio Optimization / Consolidation	ESWG, TWG	Aug 2026	Sep 2026
Project Staging	ESWG, TWG	Aug 2026	Sep 2026
Benefit Metrics Calculations	ESWG	Aug 2026	Sep 2026
Stability Analysis	TWG	Aug 2026	Sep 2026
Sensitivity Analysis	ESWG	Aug 2026	Sep 2026
Final Reliability Assessment	TWG	Aug 2026	Sep 2026
Review Draft Report with Recommended Solutions	ESWG, TWG	Aug 2026	Sep 2026
Final Report with Recommended Solutions	ESWG, TWG	Sep 2026	Sep 2026
	RSC, SPC, SSC	October 2026	
	MOPC, SPP Board		

Figure 16: 2026 Combined Assessment schedule

SECTION 8: CHANGES IN PROCESS AND ASSUMPTIONS

To protect against changes in process and assumptions that could present a significant risk to the completion of the 2026 Combined Assessment, any changes to this scope or assessment schedule must be appropriately vetted and follow the process outlined in the stakeholder accountability section of the ITP Manual as time allows.