2024 INTEGRATED TRANSMISSION PLANNING ASSESSMENT SCOPE

By SPP Engineering

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Version 1.4

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
01/17/2023 v.1.0	SPP Staff	ESWG/TWG approved Scope 1/04/2023	MOPC approved 1/17/2023
3/8/2023 v1.1	SPP Staff	Increased renewables and energy storage amounts for F1 and F2	ESWG Approved 3/1/2023
3/29/2023 v1.2	SPP Staff	Added language for extreme winter weather analysis	TWG and ESWG Approved
5/22/2023 v1.3	SPP Staff	Added language to identify the criteria to define needs in the two extreme weather scenarios	TWG and ESWG Approved
3/27/2024 v1.4	SPP staff	Removal of Voltage Stability Assessment	TWG and ESWG Approved
4/16/2024 v1.4	SPP Staff	Removal of Voltage Stability Assessment	MOPC Approved 4/16/2024

CONTENTS

SECTION 1: OVERVIEW

This document presents the scope and schedule of work for the 2024 Integrated Transmission Planning (ITP) Assessment. The Economic Studies Working Group (ESWG) and Transmission Working Group (TWG) are responsible for the creation and review of this document with approvals from the Market Operations and Policy Committee (MOPC) and the board of directors (Board).

OBJECTIVE

The objective of the 2024 ITP Assessment is to develop a regional transmission plan that provides reliable and economic delivery of energy and facilitates achievement of public policy objectives, while maximizing benefits to the end-use customer. This 2024 ITP Assessment Scope contains assumptions to be utilized in the 2024 ITP Assessment that are not standardized in the ITP Manual. These documents should be reviewed together for a comprehensive view of the 2024 ITP process and assumptions.

SECTION 2: MODELING DETAILS AND ASSUMPTIONS

MODEL YEAR DEFINITIONS

The 2024 ITP seasonal models for the 2024 ITP years two, five, and ten are listed below based on the Model Development Procedure Manual developed by the Model Development Advisory Group.

2024 ITP & NERC TPL Assessment Study Years	
ITP & TPL Assessment (Study Year)	2024
Year One	2024
Year two	2025
Year five	2028
Year ten	2033

Table 1: Model Year Definitions

MARKET ECONOMIC MODEL OVERVIEW

FUTURES

The ESWG developed two futures with input from the Strategic Planning Committee (SPC) and TWG. The MOPC reviewed both futures in October 2022.

	DRIVERS				
KEY ASSUMPTIONS	**Year 2**	**Future 1 – Reference Case**		**Future 2 – Emerging Technologies**	
	2	**5**	**10**	**5**	**10**
Peak Demand Growth Rates	As submitted in load forecast	Increase due to electric vehicle growth		Higher Increase due to electric vehicle growth	
Energy Demand Growth Rates	As submitted in load forecast	Increase due to electric vehicle growth		Higher Increase due to electric vehicle growth	
Natural Gas Prices	Current industry forecast	Current industry forecast		Current industry forecast	

KEY ASSUMPTIONS	DRIVERS				
	Year 2	Future 1 – Reference Case		Future 2 – Emerging Technologies	
	2	5	10	5	10
Coal Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Emissions Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Fossil Fuel Retirements	Current forecast	based on IRP feedback; subject to generator owner (GO) review		based on IRP feedback; subject to generator owner (GO) review	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[1]	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Energy Efficiency	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Storage	Existing + RARs	*30% of projected solar* (2.8. GW / 5.7 GW)		*40% of projected solar* (7.6 GW / 9.6 GW)	
Total Renewable Capacity					
Solar (GW)	Existing + RARs	**9.4**	**19.1**	**19.1**	**24.1**
Wind (GW)	Existing + RARs	**48.2**	**54.9**	**52.3**	**59.1**

Table 2: Future Drivers

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 EIA 860 data, as well as ABB 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 in the 2024 ITP. External areas will have the same

[1] As defined in the SPP Model Development Procedure Manual

criteria, with the deviation that external co-generation units will be assigned a must-run status subject to SPP review.

CURTAILMENT PRICE

An automatic repower will be assumed for all wind units after 10 years of being in service.

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 year 5 and year 10 MEM builds, SPP and ESWG will be reviewing 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 ITP assessment report.

RESOURCE PLAN

CONVENTIONAL GENERATOR PROTOTYPES

Generator prototype parameters will be set using the Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022 – EIA (EIA-AEO).[2] Industrial combustion turbine (CT) will be the default. Members will be allowed to request an exception to the combustion turbine utilizing the single-shaft combined cycle (CC) or 90% carbon capture combined cycle prototypes from the EIA-AEO. Exceptions must be approved by the ESWG. Table 3 below details the characteristics of the approved prototypes in 2021 dollars for currency values. The Variable O&M values will be reviewed and approved by the ESWG as part of the resource plan milestone and documented in the ITP assessment report.

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 '22**	**90% CCS**	**377**	**$2,736.00**	**TBD**	**$28.89**	**7,124**

[2] https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

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 '22**	**Single Shaft**	**418**	**$1,201.00**	**TBD**	**$14.76**	**6,431**
Combustion Turbine (CT)	**EIA AEO '22**	**Industrial**	**237**	**$785.00**	**TBD**	**$7.33**	**9,905**

Table 3: Generator Prototype Parameters

RESOURCE ACCREDITATION

Accreditation of existing renewable units from the latest SPP ELCC study results will be supplied by members through the Generation Review. If no accreditation data is submitted for a resource, then it will default to the approximate average effective load-carrying capability (ELCC) value for the respective resource (accreditation values for projected resources). Total projected utility scale solar, wind, and storage will be accredited based on the approximate average effective load-carrying capability (ELCC) value for the respective resource.

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- OR ENERGY- BASED	YEAR 5 %	YEAR 10 %
Kansas	Goal	Both	Capacity	20	20
Minnesota	Mandate	Both	Energy	25	25
Missouri	Mandate	Both	Energy	15	15
North Dakota	Goal	Both	Energy	10	10
New Mexico	Mandate	Both	Energy	40	50
South Dakota	Goal	Both	Energy	10	10
Texas	Mandate	Both	Capacity	5	5

Table 4: ITP RPS by State

NEW RESOURCE ALLOCATION AND ASSIGNMENT

100% of requested non-policy wind, solar, and storage resources will be assigned to requesting utilities. The specific resource assignments will be made in parallel with the siting milestone for the 2024 ITP.

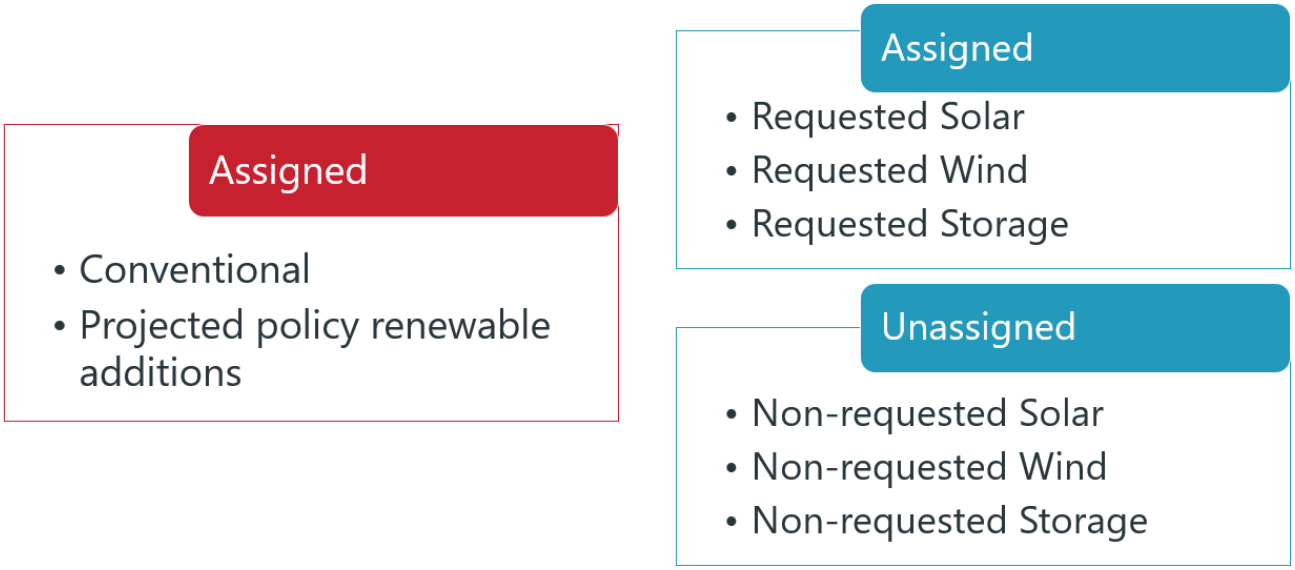

Figure 1: Resource Assignments

Policy additions will be met with 50 percent wind and 50 percent 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 figures 2 and 3 below:

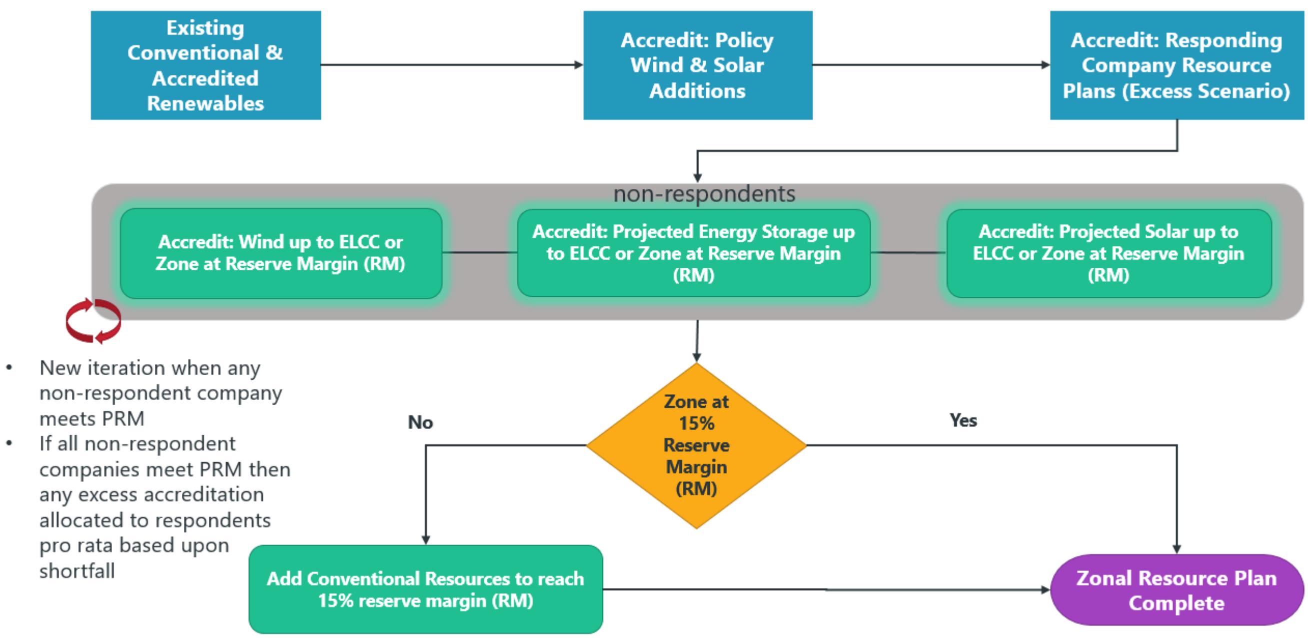

Figure 2: Resource Accreditation - Excess Scenario

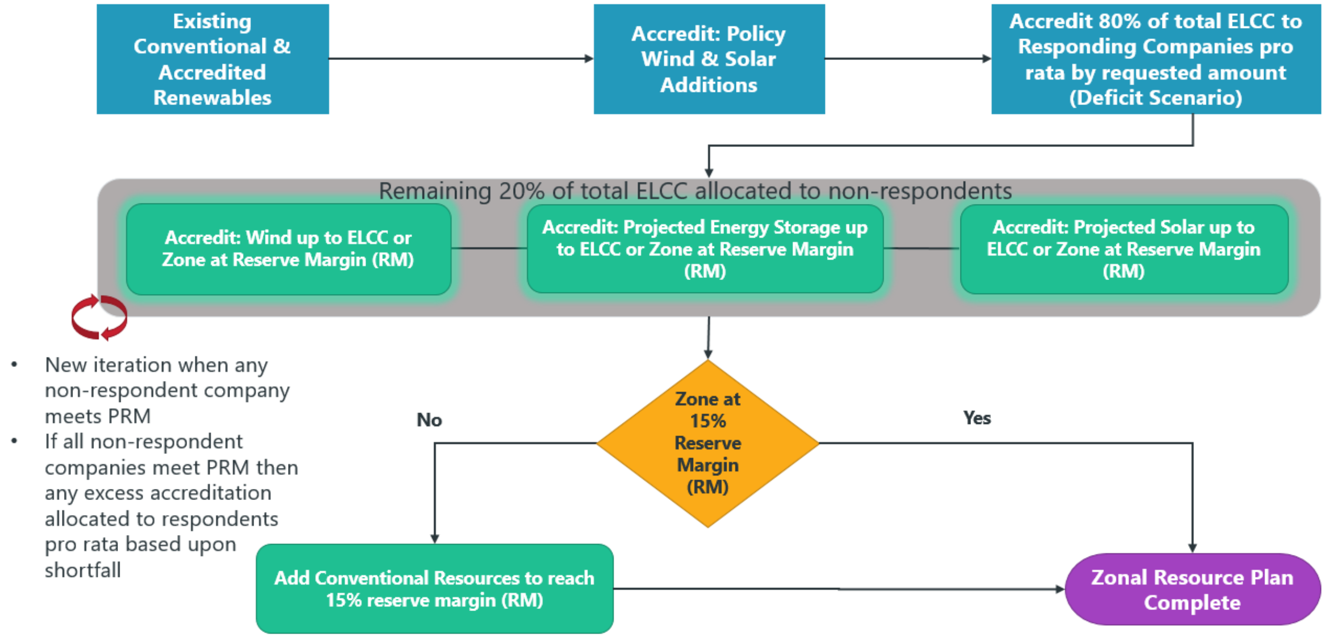

Figure 3: Resource Accreditation - Deficit Scenario

In the excess scenario responding companies receive the full amount of renewables 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 pro rata by requested amount. The remaining 20% of ELCC will be allocated to non-responding companies pro rata (all fuel types) based upon shortfall, capped at PRM.

RESOURCE PLAN MODELING

As noted in the ITP Manual, the market powerflow models (MPM) will contain system topology consistent with their respective market economic model (MEM). This topology consistency does not include the reactive power settings of the resource plans because they are not considered in the MEM. The following parameters will guide how the resource plans, both internal and external, are modeled with regards to reactive settings, such as maximum and minimum VAR support and voltage schedule. Stakeholders are given the opportunity to review certain reactive device settings during the MPM review period described in Section 2.3.2 of the ITP Manual.

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.

SOLAR, WIND, OR ENERGY STORAGE RESOURCES

The control mode for renewable and energy storage resources will be "+ or – Q limits based on WPF[3]". 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.

[3] Wind power factor

SECTION 3: EXTREME WINTER WEATHER ANALYSIS

Over recent years, SPP and its neighbors have been experiencing more frequent extreme winter conditions. Since 2018, three different winter events have affected SPP directly or indirectly, most recently Winter Storm Uri (Feb. 2020) and Winter Storm Elliot (Dec. 2022). As a result, SPP has included extreme winter weather analysis in the 2024 ITP Assessment. Two powerflow model sets will be built for evaluation for this effort. The two model sets will represent system conditions. The first model will represent a set of winter weather assumptions and their collective effect on the system. The second model will represent conditions present near the time of member-specific load shed during Winter Storm Elliott.

MODEL DEVELOPMENT

EXTREME WINTER WEATHER SCENARIO

Staff will build an extreme winter weather scenario model set based upon staff and stakeholder agreement on a set of winter weather system stressors and the expected effect to the transmission system. Extreme conditions considered in the extreme winter weather scenario will include, but not limited to:

- Effect of low temperatures
    - Load levels
    - Wind
    - Precipitation
    - Ice Dams
    - Capacity reduction
- Fuel Availability
- Imports/Exports
- Generation hardening

Three models representing the same years as the standard base reliability models will be built.

WINTER STORM ELLIOTT SCENARIO AND TARGET AREA

During Winter Storm Elliott, SPP experienced system stressors driven by a quickly falling temperatures and low wind chill values affecting generation and transmission equipment. This resulted in a strained grid that SPP was able to maintain without the need to shed load on a regional basis, however, the east portion of SPP experienced more stressed conditions, including one of SPP's members shedding load to maintain system integrity.

SPP will build two (2) powerflow models mimicking system conditions from Winter Storm Elliot. These cases will represent system conditions such as load, online generation and imports/exports observed during the storm around the time member-specific load shed occurred. The first case will be based on the SPP system's facilities online and available during Winter Storm Elliott. The second case will represent Winter Storm Elliott conditions on a year 5 model. This model will represent the conditions from Winter Storm Elliott with incremental topology updates expected to be in-service by year 5 of the 2024 ITP. Stakeholders and staff will also consider increasing regional load values consistent with the regional SPP load growth between year 2 and year 5.

Additionally, the 2024 ITP will define a target area consisting of southeast Kansas, southwest and south central Missouri, and northwest Arkansas as a result of the complications caused by conditions of Winter Storm Elliot.

CONTINGENCY ANALYSIS AND SOLUTION DEVELOPMENT

SPP will conduct N-0 and N-1 contingency analysis consistent with the ITP Manual on both extreme winter scenarios for the entire SPP region.[4] All N-0 violations will be posted as a Need for submission of solutions through the Detailed Project Proposal process. Results from N-1 contingency analysis will be included as information to support the recommended regional solution to address the N-0 extreme winter weather needs or other needs identified throughout the 2024 ITP Assessment.

N-0 needs will be those facilities with thermal loading or voltage values outside the bandwidth of allowable operation under emergency conditions (i.e. contingency conditions). Transmission lines and transformers with thermal loading of 100% or greater of its emergency rating will be identified as a need. Buses with voltages outside the acceptable bandwidth of 0.90 per unit to 1.05 per unit will also be identified as a need. For the purposes of information gathering, SPP staff will monitor utilize SPP's Planning Criteria for system intact for N-0 and N-1 analysis for both extreme winter scenarios.

[4] For the extreme winter scenarios, N-0 is intended to mean based upon the conditions of the model as built according to the guidelines approved and directed by the TWG and ESWG. This includes prior outage conditions present in the winter storm scenario based upon Winter Storm Elliot and the regional extreme winter model.

SECTION 4: SOLUTION EVALUATION & PORTFOLIO DEVELOPMENT

PERSISTENT ECONOMIC OPERATIONAL SOLUTION EVALUATIONS

FLOWGATES

SPP will perform the persistent operational needs assessment prior to the 2024 ITP benchmarking milestone for further investigation and validation of the year 2 economic models. As part of the 2024 ITP needs 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.

CONSOLIDATION

SPP must consolidate the future-specific portfolios 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. Three different scenarios could occur during the consolidation of the future-specific portfolios into a recommended plan:

1. The same project is addressing the same or similar needs in both futures
2. Different projects are addressing the same or similar needs in both futures
3. A project addresses certain needs only in one future

Projects applicable to scenario one will be considered for the recommended plan. Projects applicable to scenarios two and three will be given a score based on the point system detailed in Table 5. 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 ($M)		N/A
	40-year (1-year) APC Net Benefit in Opposite Future ($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 Issues	7.5	Y/N
6	Long Term Viability (e.g. 2013 ITP20, 2022 20-Year Assessment) or Improved Auction Revenue Right (ARR) Feasibility	5	Y/N
	Total Points Possible	**100**	

Table 5: 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
2. Calculate 40-year net adjusted production cost (APC) benefits
   - Net APC benefit$_{P1,AVE}$
   - Net APC benefit$_{P2,AVE}$
   - Net APC benefit$_{Max}$ = Maximum(Net APC benefit$_{P1,AVE}$,Net APC benefit$_{P2,AVE}$)
3. Calculate points awarded
   - $Points\ awarded_{P1,\%} = 50 \times \frac{Net\ APC\ benefit_{P1,AVE}}{Net\ APC\ benefit_{Max}}$
   - $Points\ awarded_{P2,\%} = 50 \times \frac{Net\ APC\ benefit_{P2,AVE}}{Net\ APC\ benefit_{Max}}$

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 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

2. Calculate net APC benefits
    - Net APC benefit$_{P1,AVE}$
    - Net APC benefit$_{P1',AVE}$ = Net APC benefit$_{P1,AVE}$ with 1.0 40-year B/C in opposite future
3. Calculate points awarded
    - $Points\ awarded_{P1,\%} = 50 \times \frac{Net\ APC\ benefit_{P1,AVE}}{Net\ APC\ benefit_{P1',AVE}}$

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.

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

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[5] multiplied by the points possible, up to 10.

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

OR

$$Points\ awarded = \left(\frac{Hours\ of\ system\ reconfiguration_{12\ months}}{X\%^{6} \times 8{,}760}\right) \times 10$$

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.

SPP may use engineering judgement or other analysis to support or oppose results of the systematic approach described above. 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.

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[5] 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.

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

SECTION 5: FINAL ASSESSMENTS

SENSITIVITIES

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 wind levels

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

SECTION 6: SCHEDULE

The 2024 ITP assessment began in July 2022 and will be completed by October 2024.[7] Figure 2 and Table 7 detail the study timeline.

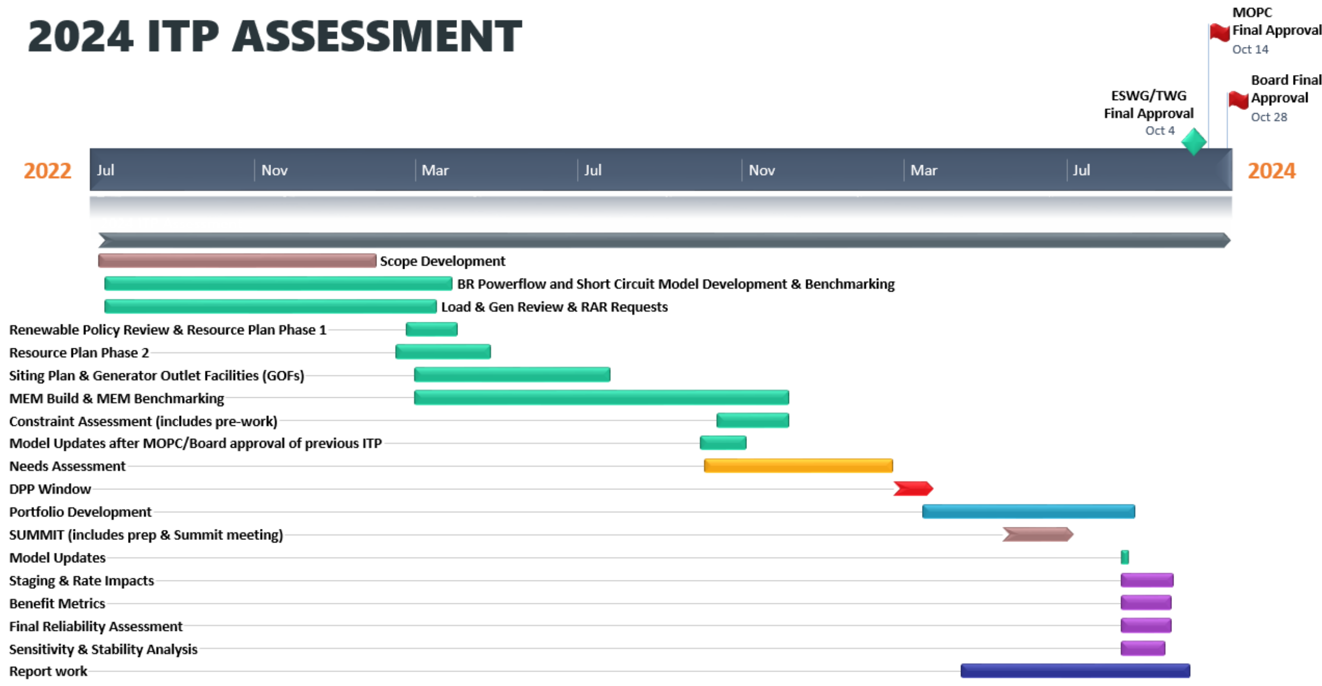

Figure 4: 2024 ITP Timeline

[7] Dates are subject to change.

MILESTONE NAME	GROUP(S) TO REVIEW/ENDORSE	START DATE	COMPLETION DATE
Scope Development	ESWG, TWG, MOPC, SPC	Jul 2022	Jan 2023
Base Reliability Powerflow & Short Circuit Model Development	TWG	Jul 2022	Mar 2023
Load and Generation Review	ESWG, TWG, MDAG	Jul 2022	Mar 2023
Renewable Policy Review	ESWG	Jan 2023	Mar 2023
Renewable Resource Plan (RP1)	ESWG, CAWG	Feb 2023	Mar 2023
Conventional Resource Plan (RP2)	ESWG	Mar 2023	May 2023
Siting Plan & Generator Outlet Facilities (GOFs)	ESWG	Mar 2023	Jul 2023
Powerflow Model Development	TWG	Mar 2023	Nov 2023
Short Circuit Model Development	TWG	Mar 2023	Nov 2023
Economic Model Development	ESWG	Mar 2023	Dec 2023
Model Benchmarking	ESWG, TWG	Jul 2023	Sept 2023
Model Updates after 2023 ITP Approval MOPC/Board (NTC/Re-evaluations)	TWG	Oct 2023	Nov 2023
Constraint Assessment	TWG	Nov 2023	Dec 2023
Needs Assessments	ESWG, TWG	Nov 2023	Mar 2024
Detailed Project Proposal (DPP) Window	ESWG, TWG	Mar 2024	Apr 2024
Solutions Development	ESWG, TWG	Mar 2024	May 2024
Project Grouping	ESWG, TWG	Apr 2024	May 2024
Study Cost Estimates		Jun 2024	Aug 2024
Summit		July 2024	July 2024
Final Portfolio Development	ESWG, TWG	July 2024	Aug 2024
Portfolio Optimization / Consolidation	ESWG, TWG	Aug 2024	Sep 2024
Project Staging	ESWG, TWG	Aug 2024	Sep 2024
Benefit Metrics Calculations	ESWG	Aug 2024	Sep 2024
Stability Analysis	TWG	Aug 2024	Sep 2024
Sensitivity Analysis	ESWG	Aug 2024	Sep 2024
Final Reliability Assessment	TWG	Aug 2024	Sep 2024
Review Draft Report with Recommended Solutions	ESWG, TWG	Aug 2024	Sep 2024
Final Report with Recommended Solutions	ESWG, TWG	Sep 2024	Sep 2024
	RSC, SPC, SSC	October 2024	
	MOPC, SPP Board		
	MOPC, SPP Board		

Table 6: 2024 ITP Schedule

SECTION 7: CHANGES IN PROCESS AND ASSUMPTIONS

To protect against changes in process and assumptions that could present a significant risk to the completion of the 2024 ITP 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.