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

2.2.1.9 Hurdle Rates

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

2.2.1.10 Renewable Pricing

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

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

To model a curtailment price for wind units that will reflect market operation, including projected production tax credit (PTC) impacts, the following criteria will be used for wind curtailment price modeling:

- Wind units will have $0/MWh curtailment price if any of the following are true[18]:
  - The unit is placed in service over 10 years prior to the study year.
  - Construction on the unit has not started prior to January 1, 2020.
  - An entity associated with the unit has provided feedback that the investment tax credit (ITC), rather than PTC, is applicable.
- Otherwise, wind units will have a negative $35/MWh curtailment price to reflect the "grossed-up" value of a PTC[19].

To model a curtailment price for solar units that will reflect market operation, the curtailment price will be set at $0/MWh.

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

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

2.2.1.11 Must Run Units

Must-run units in the ITP assessment are dispatched during all available hours to their minimum capacity states, regardless of economics. Must-run statuses will be removed from all units at the

[18] Reflecting that the PTC is not a factor in its operation
[19] Reflecting income tax compensation

start of each study. In the development of the ITP study scope, the ESWG will determine if must-run units will be allowed and the criteria needed for such designation. Individual generating units meeting must-run criteria will be identified by SPP or stakeholders during the generation review and subject to approval by the ESWG.

2.2.2 RESOURCE PLAN

2.2.2.1 Resource Expansion Plan

After forecasted load and existing and planned generation have been defined through the SPP annual data request, analysis will be conducted to determine new (conventional and renewable) resource additions required in years 5 and 10 for each future in the economic and Market Powerflow model. Resource additions are included to develop realistic future-year models by accounting for reserve margin requirements, historical trends, economics, etc. The resource-planning phase will identify new units and the associated parameters for these new units, but will not include any siting considerations, which will be addressed in the Resource Siting Plan section. The year 2 models will be assessed to evaluate whether the reserve margin requirements are being met at the SPP BA level.

2.2.2.1.1 Renewable Resource Expansion Plan

SPP shall develop a resource plan to meet renewable expectations for the region. This will include capacity as required through the renewable policy review, as well as capacity identified through criteria developed by SPP and stakeholders. Consideration will be given to the futures being studied and factors such as government regulations, historical trends, natural gas prices, installation trends, integrated resource plan projections, and SPP stakeholder feedback.

Renewable additions will be computed using criteria that can be applied uniformly across pricing zones.[20] For example, each pricing zone should have renewable capacity of at least a certain percentage of their annual peak-load responsibility. Renewable resources other than wind and solar (such as biomass) shall only be added to the model as defined in the Generation Resource Inclusion and Generation Resources sections.

External regions and areas that are economically dispatched in the model may include renewable additions beyond the units planned at the time of study. An appropriate resource plan from the most current external entity's study will be used for their region in the ITP assessment, if readily available and appropriate. These resource plans are future-specific.

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

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

2.2.2.1.2 Conventional Resource Expansion Plan

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

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

Resource expansion software will be used in all futures to identify the optimal mix of new conventional resource additions needed for the SPP region.[21] The magnitude of resource additions will be based on resource shortfalls. Ownership of conventional unit additions will be allocated to pricing zones such that each pricing zone approximately meets the reserve margin requirement. Joint ownership of unit additions may be used to avoid excessive additions of new resources to individual pricing zones.

External regions also will be analyzed for resource shortfalls. An appropriate resource plan from the most current neighboring entity's study will be used for their region in the ITP assessment, if readily available and SPP and stakeholders find it appropriate. The use of their resource plan is future specific. If there is not a future comparable to the ITP future, as determined by SPP and the ESWG, then conventional additions to address shortfalls shall be added to external regions with a resource mix that is as close as possible to the SPP conventional resource addition mix for that future. For example, if SPP conventional resource additions include 60 percent combined cycles and 40 percent combustion turbines, a ratio as close as possible to this 60/40 ratio would be used to guide conventional resource additions in external regions.

2.2.2.2 Resource Siting Plan

2.2.2.2.1 Siting Process

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

2.2.2.2.2 Site Repository

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

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

22 Resource Siting Manual

2.2.2.2.3 Process Flow

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

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

2.2.2.2.4 Siting for External Regions

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

2.2.2.3 Generation Outlet Facilities

Once the resource and siting plans have been finalized, SPP will reconsider the First Contingency Incremental Transfer Capability analysis completed during the siting process to develop any necessary generator outlet facilities (GOFs). This GOF process is intended to proxy the evaluation of a resource in the generator interconnection process to develop necessary upgrades.

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

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

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

2.2.3 CONSTRAINT ASSESSMENT

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

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

- Copper Plate: No defined constraints.
- Initial constraint list based on NERC and SPP flowgates.

2.2.3.1 Contingency Screening

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

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

- P1.2 and P1.3 single-branch contingencies on the 100 kV and above system exceeding 50 percent loading in the peak and off-peak hours under system intact conditions for the translated areas.
- P1.2 and P1.3 single-branch contingencies on the 200 kV and above system exceeding 25 percent loading in the peak and off-peak hours under system intact conditions for the SPP footprint.
- Contingencies included in the SPP permanent and temporary flowgates, including P7 events.
- Other P1, P2, P4 and P5 events as potential contingencies.

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

2.2.3.2 Constraint Identification

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

- Number of violation hours and/or violation loading thresholds.
- The ability of the simulation to reach a valid[24] dispatch solution due to a given constraint[25].
- Preliminary economic model simulation results.
- Performance of constraints in prior SPP expansion plan studies.

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

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[23] Defined in the Market Powerflow Model Overview section

[24] All constraints and generating parameters honored

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

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

2.3 MARKET POWERFLOW MODEL OVERVIEW

Each Market Powerflow model is an AC powerflow representation of a specific one-hour snapshot of an economic model run with SPP acting as its own balancing authority. Each Market Economic model developed will have two AC powerflow models developed based upon system conditions of a single hour within the year. The two hours represented will be the SPP coincident peak hour (peak) and the hour with the highest wind penetration between April and May between the hours of 12 a.m. - 6 a.m. (off-peak). The models will be developed by matching the dispatch in each powerflow model to the dispatch in the respective hour of the economic model simulations. This process will be described later in the Conversion section. After the conversion is complete, SPP and stakeholders will assess reactive power flows on the system that the economic modeling tools are unable to represent. Some of the Market Powerflow models will be used to meet the requirements of a sensitivity case necessary for NERC Standard TPL-001 compliance.

AC powerflow models considering a SCUC and SCED solution during SPP coincident peak load and off-peak load conditions will be developed for each future scenario and study year. These models will contain system topology[26] consistent with their respective economic model.

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

2.3.1 DC/AC CONVERSION

2.3.1.1 Generation

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

2.3.1.2 Load Forecasts

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

2.3.1.3 Interchange

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

[26] System topology includes the transmission network and location of generation, load and reactive devices.

2.3.2 REACTIVE DEVICE SETTINGS

After the DC/AC conversion process is complete, SPP and stakeholders will have an opportunity to review the settings for transmission facilities that provide reactive support for the transmission system. SPP stakeholders will submit changes to set points for capacitors, reactors, tap changers for transformers, remote buses, voltage schedules for generators, and static VAR compensators. These adjustments will improve the response of the transmission system under system intact and contingency conditions as well as provide confidence to SPP and stakeholders that potential violations are based on realistic system conditions prior to the reliability needs assessment.

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

2.4 OPERATIONAL MODEL DEVELOPMENT

After persistent operational needs are identified, SPP will identify the most extreme case(s) to evaluate whether the needs are addressed with proposed solutions. SPP will use an energy management system snapshot model for reliability operational needs and the day ahead reliability unit commitment (DA-RUC) model for economic operational needs. Times with high loading or that require voltage mitigation for each operational need will be selected and the models converted to an ITP model format.

2.5 INTERREGIONAL COORDINATION

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

3 BENCHMARKING

3.1 POWERFLOW MODEL

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

3.2 ECONOMIC MODEL

The year 2 economic model will be utilized to validate modeling parameters to determine if operation is reflective of the SPP system. Data validation may include: capacity factor by unit type, maintenance outages, operating and spinning reserves, average energy costs, system LMPs (zonal, average, max, etc.), interchange, APC comparison, and renewable generation profiles. Data may be compared to the most recent SPP operational data and previous study models.

4 NEEDS ASSESSMENT

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

4.1 ECONOMIC NEEDS ASSESSMENT

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

4.1.1 SCUC & SCED ANALYSIS

The economic needs of the system will be identified to develop a portfolio for each future. All of the economic system needs will be identified through the use of a security-constrained unit commitment (SCUC)/security-constrained economic dispatch (SCED) simulation that accounts for every hour of the study years.

The SCUC/SCED simulation requires a dual-optimization process. During the SCUC, the hourly least-cost combination of units that should be committed (turned on or off) is determined, subject to unit-specific operational constraints (e.g., ramping, minimum output, min/max runtime, startup cost, etc.) and some critical location-specific transmission reliability constraints (e.g., must-run operational limits). The SCUC does not explicitly consider transmission grid operational costs.

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

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

4.1.2 NEED IDENTIFICATION

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

1. Binding constraints will be ranked from highest to lowest congestion score. Congestion score is defined as the product of a given constraint's average shadow price[27] and the number of hours that constraint is binding.

Figure 2 Congestion Score Formula

2. A list of binding constraints will be reduced to the congested flowgates that have greater than $50,000/MW in annual flowgate congestion score. However, additional constraints may be included if SPP determines the inclusion would better define an economic need overall.[28]

3. Constraints with monitored elements not interconnected with the SPP transmission system that provide less than $1 million in annual potential benefit to SPP will be removed unless SPP determines the constraints are related to a target area or a historically congested market-to-market flowgate and warrant further analysis.[29]

[27] The shadow price represents the potential reduction in total SPP production costs if the limit on a congested flowgate could be increased by 1 MW.

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

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

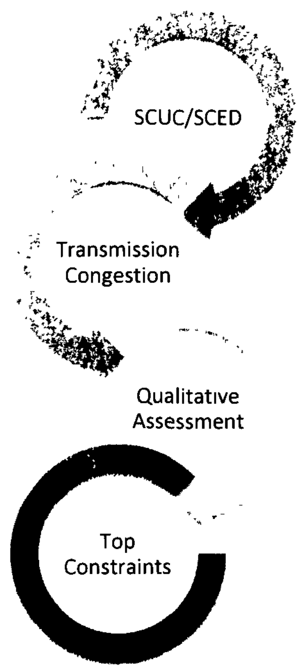

Figure 3 Economic Need Development

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

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

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

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

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

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

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

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

4.2 RELIABILITY NEEDS ASSESSMENT

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

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

4.2.1 BASE RELIABILITY MODEL

Contingency analysis for the base reliability model will consist of analyzing P0, P1, and P2.1 planning events identified in NERC Standard TPL-001 Table 1 for each of the models. The voltage level for monitored and contingent elements in the SPP footprint are described in more detail in Table 3.

[31] SPP Planning Criteria

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

Table 3. NERC Standard TPL-001 Planning Events as Monitored and Contingent Elements

The base reliability models will be analyzed with the remaining contingencies from Table 1 in the NERC Standard TPL-001 that do not allow for NCLL or IFTS as detailed in Table 4.

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

Table 4 Remaining Contingencies for Monitored and Contingent Elements

4.2.2 MARKET POWERFLOW MODEL

Contingency analysis for the Market powerflow models will consist of analyzing P0, P1, and P2.1 planning events identified in NERC Standard TPL-001 Table 1 for each of the models. The voltage level for monitored and contingent elements in the SPP footprint are described in more detail in Table 5.

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

	P0, P[illegible]2.1	
	Monitored Element	Contingent Element
Reference Case Year 2 Peak	100 kV+ with select 69 kV facilities	100 kV+ with select 69 kV facilities
Reference Case Year 2 Off-Peak		
Reference Case Year 5 Peak		
Reference Case Year 5 Off-Peak		
Reference Case Year 10 Peak	100 kV+	100 kV+
Reference Case Year 10 Off-Peak		
F_X Year 5 Peak		
F_X Year 5 Off-Peak		
F_X Year 10 Peak		
F_X Year 10 Off-Peak		

Table 5 NERC Standard TPL-001 Planning Events as Monitored and Contingent Elements

The remaining contingencies in Table 1 of the NERC Standard TPL-001 that do not allow for NCLL or IFTS will be analyzed if a violation was observed in the same year/season of the base reliability model as detailed in Table 6.

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

Table 6 Remaining Contingencies for Monitored and Contingent Elements

4.2.3 NON-CONVERGED CONTINGENCIES

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

4.2.4 FIRST-TIER CONSIDERATION

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

4.2.5 VIOLATION FILTERING

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

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

4.2.6 LOCAL PLANNING CRITERIA

Local planning criteria will be collected from SPP TOs in accordance with the SPP tariff. Auxiliary files will be updated with the latest TO local planning criteria information. SPP will request the TOs

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

validate the updated auxiliary files which will be used during the base case and contingency analysis. The local planning criteria needs will be posted on a secure website.

4.2.7 SHORT-CIRCUIT ANALYSIS

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

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

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

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

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

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

4.3 PUBLIC POLICY NEEDS ASSESSMENT

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

4.4 PERSISTENT OPERATIONAL NEEDS ASSESSMENT

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

4.4.1 ECONOMIC OPERATIONAL NEEDS

SPP will classify flowgates meeting either of the following criteria as economic needs:

1. The flowgate was congested for at least 20 percent of the previous 24 months, either in a breached or binding state in the real-time balancing market solution, or
2. The flowgate had congestion costs[37] totaling more than $10 million over the previous 24 months.

Periods of time when a flowgate's related congestion is deemed to be the result of prior outage conditions will be excluded from these criteria calculations. Congestion cost for outages will be provided for informational purposes.

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

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

4.4.2 RELIABILITY OPERATIONAL NEEDS

SPP will classify facilities as reliability needs due to system reconfiguration using agreed upon (by SPP and the transmission operator) operational guides or load shed as a result of unsuccessful control of the system through re-dispatch if they meet the following criteria:

1. High- or low-voltage issues where system reconfiguration is implemented 10 percent of the year due to non-outage issues[38], or
2. Thermal loading issues where system reconfiguration through the use of an agreed upon operating guide has been implemented in real-time 25 percent of the year.

[37] Congestion costs will be calculated using the same methodology as the SPP violation relaxation limit process.
[38] Switched shunts and generator MVAR adjustments will be optimized prior to needs being identified. If potential non-consequential load loss is 100 MW or greater, the risk to the load would need to be present one percent of the time.

5 SOLUTION DEVELOPMENT AND EVALUATION

5.1 DETAILED PROJECT PROPOSAL PROCESS

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

5.1.1 SOLUTIONS

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

5.1.1.1 Transmission Projects

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

5.1.1.2 Non-Transmission Solutions

Non-transmission solutions are generally considered a method of modifying existing facility settings, inputs, outputs, or other changes to the existing transmission system such that at least one need is mitigated, but can also include new projects such as generation capacity additions.

5.1.1.3 Model Adjustments

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

5.1.1.4 Operating Guides & Planning Guides

SPP stakeholders can submit current SPP operating guides to mitigate needs. Once submitted, SPP will verify the operating guide is still active prior to solution testing.

5.1.2 SPP DEVELOPED SOLUTIONS

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

5.2 COST ESTIMATES

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

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

5.3 SOLUTION EVALUATION PROCESS

5.3.1 ECONOMIC SOLUTION EVALUATION

All solutions[39] will be evaluated based on their one-year benefit-to-cost ratio (B/C) and 40-year net present value (NPV) B/C, using conceptual cost estimates. If a solution mitigates congestion for an economic need and has at least a 0.5 one-year B/C or a 1.0 40-year NPV B/C, it will be included for further consideration during portfolio development. For the 40-year NPV B/C, the average SPP net plant carrying charge and an in-service date of year 5 will be applied.

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

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

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

5.3.2 RELIABILITY SOLUTION EVALUATION

All solutions[40] will be evaluated against reliability needs. SPP will use the following metrics to evaluate potential benefits-to-proposed cost:[41]

- Cost per loading relief (CLR[41])– relates the cost of a proposed solution to the amount of thermal loading relief for a need
- Cost per voltage relief (CVR[41]) – relates the cost of a proposed solution to the amount of voltage support relief for a need

The CLR and CVR metrics will be calculated for every solution against each need it mitigates. Solutions that change the status of a unit requested to be offline due to seasonal availability (not

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

outage related), may be used to mitigate violations identified as a result of the resource being made available. The metric calculations will provide a ranking of the solutions for each need. SPP will use the metrics as a tool during project selection for the reliability portfolio development.

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

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

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

5.3.3 PUBLIC POLICY SOLUTION EVALUATIONS

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

5.3.4 PERSISTENT OPERATIONAL SOLUTION EVALUATIONS

A subset of solutions will be evaluated to address persistent operational needs utilizing the filtering criteria, as approved by the TWG, ESWG and ORWG. Reliability solutions will be evaluated by the CLR and CVR metrics described in the **Error! Reference source not found.** section. Economic solutions will be evaluated based on criteria developed by SPP and stakeholders, which will be detailed in the study scope.

The needs will be evaluated using operational models that capture actual historical occurrences. The ORWG, TWG, and ESWG will approve these operational models to ensure consistency with the criteria established in the Persistent Operational Needs Assessment section.

6 PORTFOLIO DEVELOPMENT

6.1 PORTFOLIO DEVELOPMENT METHODOLOGIES

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

6.1.1 ECONOMIC PORTFOLIO DEVELOPMENT

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

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

In addition to economic performance, consideration of the following information may be given to the top-ranking solutions:[42]

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

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

[42] Additional consideration may result in changes in top-ranking solutions, including elimination of solutions.

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

6.1.2 RELIABILITY PORTFOLIO DEVELOPMENT

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

6.1.3 PUBLIC POLICY PORTFOLIO DEVELOPMENT

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

6.1.4 PERSISTENT OPERATIONAL PORTFOLIO DEVELOPMENT

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

6.1.5 PORTFOLIO SYNERGY

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

6.2 PORTFOLIO CONSOLIDATION

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

6.3 PROJECT STAGING

A project implementation plan will be developed for the final consolidated portfolio(s). The final portfolio(s) will be structured such that each element can be implemented in a staged manner as actual system developments approach the assumptions resulting in the need for that element. To help stage the projects, SPP will utilize simulation results for years 2, 5, and 10.

Each project classification will have its own methodology to determine a need date for upgrades to be included in the consolidated portfolio. Step changes between models, such as new generation or transmission upgrades in an area where an upgrade has been identified, may conflict with staging results for methods described in this section. In these instances, SPP will consider these step changes within the model set to inform need date recommendations. During project staging, SPP will also consider future assumptions, current market conditions, and other available transmission system information.

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

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

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

6.3.1 ECONOMIC PROJECTS

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

Other economic projects in the final consolidated portfolio will be staged in the first year that the B/C ratio of each upgrade exceeds 1.0. A linear interpolation of B/C ratios between each of the study years will be used to determine the need date. For example, an upgrade identified to address an economic need in year 10 will be staged between year 5 and year 10, based on linear interpolation of B/C ratios between the year 5 and year 10 models. Figure 4 represents the linear interpolation of B/C ratios of an upgrade. In this example, if year 5 is 2020 and year 10 is 2025, the need date would be 2024.

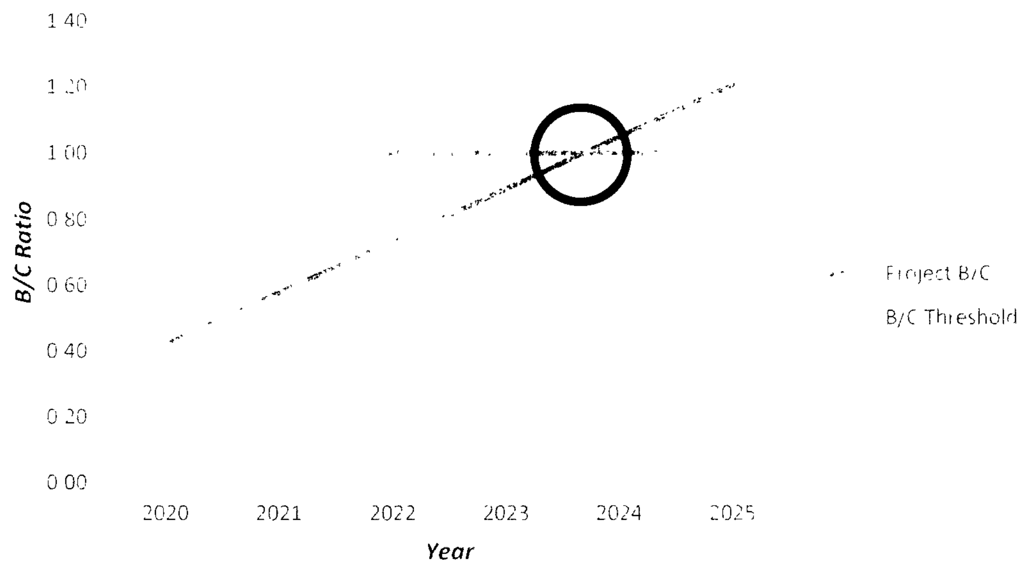

Figure 4 Economic Project Staging Example

6.3.2 RELIABILITY PROJECTS

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

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

For upgrades that solve reliability needs in year 5 and year 10, the staging process will use a linear interpolation to evaluate thermal loading or the per-unit voltage value of the season in which the violation appears and the previous year's model on record. For example, a violation that occurs in year 5 summer peak will be staged between the summer peaks of year 2 and year 5 based on the results of linear interpolation between the year 2 and year 5 summer-peak models

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

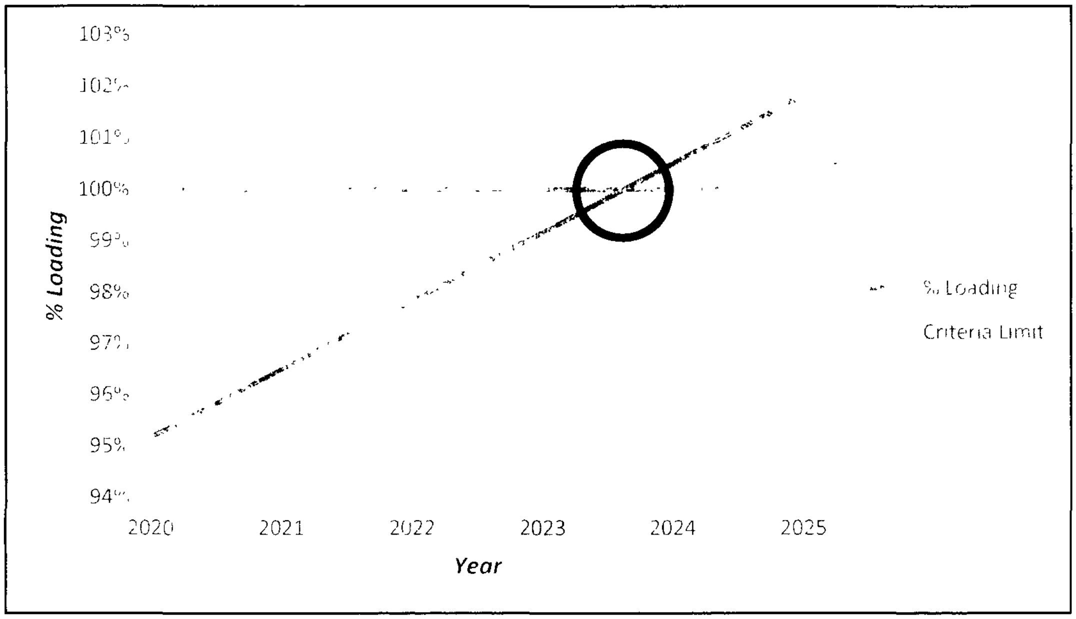

Figure 5 Reliability Project Staging Example

6.3.3 PUBLIC POLICY PROJECTS

Policy projects in the final consolidated portfolio will be staged according to when the public policy needs are resolved. A linear interpolation of the progress towards mitigating the public policy needs between each of the study years will be used to determine the staging date. For example, an upgrade identified to address public policy needs in year 10 will be staged between year 5 and year 10, based on linear interpolation of progress towards mitigating the public policy need between the year 5 and year 10 models. Figure 6 represents the linear interpolation of progress towards resolving a public policy need. In this example, if year 5 is 2020 and year 10 is 2025, the need date would be 2024.

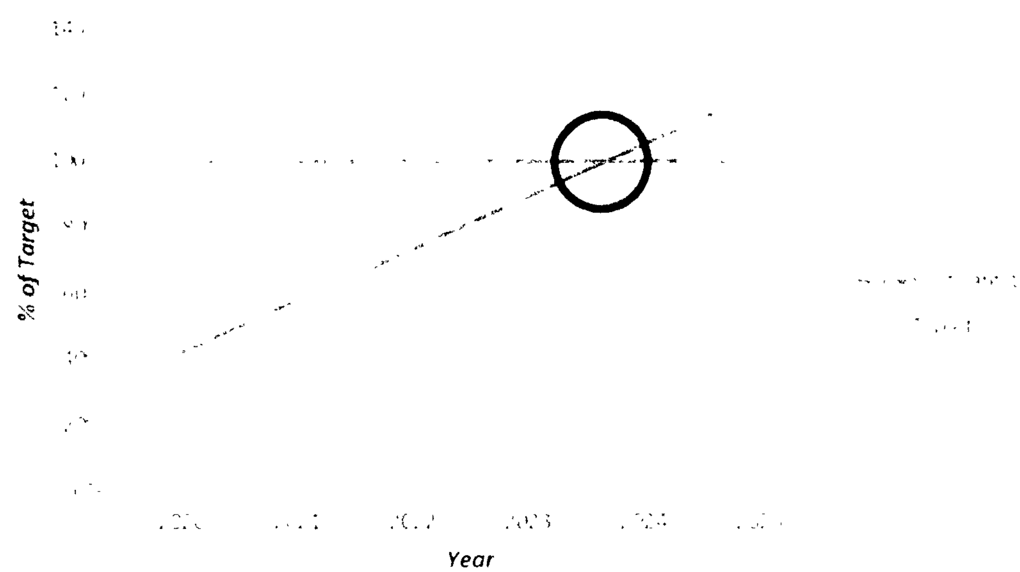

Figure 6 Public Policy Project Staging Example

6.4 FINAL RELIABILITY ASSESSMENT

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

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

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

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

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

7 INFORMATIONAL PORTFOLIO ANALYSIS

7.1 BENEFIT METRICS

Benefit metrics will be used to measure the value and economic impacts of the final consolidated portfolio to be expected from the ITP assessment. Generally, a single portfolio will be tested in the approved future(s) by computing benefits and costs over a 40-year timeframe. For further detail on the metrics in Table 7, refer to the Benefit Metrics Manual.[43]

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

Table 7 ITP Assessment Benefit Metrics

7.2 SENSITIVITY ANALYSIS

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

- High natural-gas price
- Low natural-gas price
- High demand
- Low demand

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

[43] Benefit Metrics Manual

8 DELIVERABLES

8.1 FINAL REPORT

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

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

9 ISSUANCE OF NTCS

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

10 SPP AND STAKEHOLDER ACCOUNTABILITY

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

10.1 PROJECT SCHEDULE

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

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

10.2 POINT OF CONTACT

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

Using the project schedule described in this section, SPP stakeholders will appoint a CPOC to work with SPP to coordinate the timely flow of information. Once provided to SPP, a list of SPP stakeholder contacts will be developed and posted on SPP's secure website, viewable to those with access to the website[44] and corresponding ITP assessment folder.

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

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

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

10.3 SCHEDULE IMPACTS AND MITIGATION

Stakeholders are responsible for providing the data necessary to model their assets to SPP. <u>All required model data must be received by the specific deadlines and milestones listed in the ITP schedule[45] for model development. The schedule will be provided to all stakeholders and posted on the SPP website.</u>

In the absence of newly submitted data, applicable SPP working groups and SPP will agree upon proxy data to be used to meet schedule deadlines and avoid process delays. Along with the timely submittal of data, data reviews and required approvals will be conducted by the schedule deadlines. Failure to perform the required review in a timely manner should not cause a delay in the corresponding process. In the event review deadlines are missed, the items requiring review or approval will be used as is and the process will move forward without delay.

Any entity that does not meet the prescribed data exchange, review or approval deadlines and/or want to add or change data used in the study process may make a request for consideration of the proposed data to SPP. SPP will assess the proposed data to determine if the request will have a material impact on study results and schedule. For requests that do not impact the planning process, results or schedule, the data will be included by SPP and the study process will continue. For requests that will have an impact on the study process or results and subsequently an impact to the study schedule, the submitting SPP stakeholder will be informed of the potential impact and a waiver request will be required. Along with impacts that may cause the study schedule to be altered, a waiver request may also be required when the SPP stakeholder-submitted request increases the cost of the study.

SPP may also request a waiver if a process issue causes a negative impact to the study schedule, results, or the SPP budget. SPP will assess the issue and provide feedback to the appropriate working group(s) for consideration of a waiver. Upon a working group recommendation, SPP may move forward with a waiver request.

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

With MOPC's quarterly meeting schedule and the need for an immediate resolution of a waiver request, SPP may request that MOPC conduct an out-of-schedule meeting to review and vote on a waiver request.

10.4 MOPC REPORT

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

A summary of the participation of SPP and stakeholders will inform MOPC of the importance of the successful completion of milestones and adherence to deadlines critical to produce a complete, high

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

quality, and timely report and portfolio. Issues requiring mitigation, as mentioned previously in this section, whether through the actions of SPP or stakeholders will be presented in sufficient detail to give MOPC a clear picture of the issue and remedies put in place to avoid potential impacts to the process schedule.

11 APPENDICES

11.1 HISTORY OF THE ITP ASSESSMENT

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

The SPPT recommended that the organization adopt a new set of planning principles, develop and implement an ITP assessment, develop a plan to monitor the construction of projects approved through the ITP assessment, identify priority projects that continue to appear in system reviews to relieve congestion on existing constraints, and connect SPP's eastern and western regions. The SPPT recommended the Regional State Committee (RSC) establish a "highway/byway" cost allocation methodology for approved projects.[46]

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

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

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

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

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

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

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

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

11.2 THE TRANSMISSION PLANNING IMPROVEMENT TASK FORCE

In February 2015, the Transmission Planning Improvement Task Force (TPITF) was assembled by the SPC and the MOPC and given the responsibility for developing recommendations to improve the regional planning processes. Their objective was to make the SPP transmission planning process more responsive to the effects of the continued growth of SPP's transmission system, changes in the SPP markets, challenges and opportunities presented by changing federal and state energy and environmental regulations and increasing NERC compliance requirements. The TPITF was tasked with reviewing, evaluating and proposing recommendations on the following:

1. The methodologies and modeling practices used in the generator interconnection studies, aggregate transmission service studies, integrated transmission planning (near-term, 10-year, and 20-year assessments), SPP assessments for compliance with NERC TPL standards and the MDWG model development process to ensure effectiveness, consistency and to determine if gaps exist between the various processes.
2. The utilization of data, including data collected by operations, which will benchmark the real-time and planning horizon assessments to ensure consistency in the planning process.
3. The appropriateness of the planning cycle and assessments, including the effectiveness of using production cost modeling in more assessments; development, use and weighting of futures, scenarios and sensitivities; the metrics used to evaluate proposed projects, in particular those that evaluate the impact on rate payers; and planning the transmission system beyond the traditional planning criteria of first contingency ("N-1") in accordance with the approved NERC Standard TPL-001.

The TPITF recommendation whitepaper[47], was intended to represent a consolidated, coordinated approach in planning, managing, and maintaining the SPP transmission system, with a particular emphasis on increasing the availability of transmission service to SPP's customers without unduly compromising system reliability. The recommendations in the TPITF recommendation whitepaper were intended to enable the cost-effective use of capital-intensive generating resources for the benefit of all end-use customers in the SPP footprint and to further develop and enhance policies, tools and practices to optimize the use of the transmission system. The TPITF developed five recommendations to accomplish this scope of work that are discussed in detail throughout this manual:

1. Replace the current ITP schedules with an annual transmission expansion plan.
2. Create a standardized scope.[48]
3. Establish a common planning model for use across the various SPP planning processes.
4. Utilize a holistic planning process.
5. Create SPP staff/stakeholder accountability process for the timely exchanges of data, reviews and approvals.

11.3 ACRONYMS

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

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

11.4 DEFINITIONS

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

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

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' THIRD REQUEST FOR INFORMATION

Question No. TIEC 3-4:

Provide all work papers (in native Excel format with formulas intact) used to project the PROMOD 2024 and 2029 results to the 2021 – 2051 timeframe for all scenarios studied.

Response No. TIEC 3-4:

All calculations used to project the congestion and loss costs associated with delivering the Selected Wind Facilities to the AEP West load zone, for 2021-2051, were filed in witness Sheilendranath's workpaper, "Sheilendranath WP1a – R Code_With Outputs". Specifically, see "R" code files: "Base Case Congestion and Loss Aurora Adjustment.R" and "No SPP Upgrade Congestion and Loss Aurora Adjustment.R". A description of each code file is provided in "Explanation of Code.pdf".

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' THIRD REQUEST FOR INFORMATION

Question No. TIEC 3-5:

Please provide a schedule of hourly LMPs in EXCEL format derived from the PROMOD model runs both before and after the Wind Project.

a. For the SWEPCO system.

b. At each SWEPCO generating node, including the proposed Wind Projects.

Response No. TIEC 3-5:

a. As explained in witness Sheilendranath's direct testimony, the Company's customer benefits analysis combined PROMOD results with AURORA prices. The adjusted AURORA hourly LMPs used in the Company's customer benefits analysis are provided in Mr. Sheilendranath's workpaper "Sheilendranath WP1a – R Code_With Outputs", under the "LMPs" subfolder within the "Output" folder. The column titled "aurora_adjusted_aep_load_lmp" contains load LMPs for AEP West load zone, which are applicable to SWEPCO loads. The column titled "aurora_adjusted_swepco_lmp" contains generation-weighted average adjusted-AURORA LMPs for the SWEPCO system's thermal generation units.

b. See PROMOD files containing LMPs at each SWEPCO generating node in "Sheilendranath WP1a – R Code_With Outputs", under the "Raw" folder. "F1_Y05_SlctBids_withconst_add_ndrem_Final_lmp.xlsx" and "F1_Y10_SlctdBids_withconst_add_ndrem_Final_lmp.xlsx" correspond to the "Base Case" in 2024 and 2029 respectively, while "F1_Y05_SlctdBids_withconst_add_Final_lmp.xlsx" and "F1_Y10_SlctdBids_withconst_add_Final_lmp.csv" correspond to the "No SPP Upgrades Case" LMPs in 2024 and 2029 respectively.

   The "Plant_Mapping.xlsx" file in the "Raw" folder maps bus numbers to PROMOD generators, and indicates bus numbers corresponding to various SWEPCO generation price nodes. The three proposed wind projects -- Traverse, Maverick, and Sundance -- correspond to bus numbers 515497, 520882, and 514778, respectively.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' THIRD REQUEST FOR INFORMATION

Question No. TIEC 3-6:

Please provide a revised net benefits analysis using the low gas no CO2 prices and P50 capacity factor but reduce gas prices by 10%.

Response No. TIEC 3-6:

The Company does not have a complete set of Fundamentals consistent with that gas price assumption. This would be needed in order to prepare the detailed PLEXOS production costing analysis required to produce the requested net benefits analysis, and therefore the requested case has not been prepared.

However, as described on pages 20 and 21 of Company witness Torpey's testimony, the Company did prepare a breakeven power price analysis which was based off of net benefits in the Low No Carbon case. That analysis is provided on the "P50 BE Gas" worksheet in the file "Torpey Errata Benefits Model Final" contained within the "TIEC_1_19_Supplemental-Attachment_1_Torpey_Errata_Workpapers" file that was provided in the Company's supplemental response to TIEC question 1-19. That analysis shows that a power price that was 21% lower than the Company's Low No Carbon forecast would result in zero NPV of net customer benefits. Witness Bletzacker then used this reduction in power price to estimate what gas price would be consistent with those power prices. He calculated that the average breakeven gas price would be 18.5% lower than his Low no Carbon gas price. His workpapers were provided in Attachment 1 to the Company's supplemental response to TIEC Question 1-11. This 18.5% percentage reduction is equal to one minus Column N divided by Column F on the "SWEPCO Break-Even Gas Errata" worksheet in the file named "Bletzacker Errata_2019H1_LTF_NoCO2_Low_Nominal_2019-04-23 with SWEPCO Break-Even Calcs and Errata 8-19-2019.xlsx". This gas reduction is larger than a 10% reduction, and therefore the Company would expect net benefits to be positive if it were to complete the requested analysis.

Based on a simple extrapolation between the $236M NPV of net benefits ($971M 31 year nominal) Low No Carbon case provided on page 5 of witness Torpey's Errata Exhibit JFT-3 and his breakeven gas case, which has a $0 NPV of net benefits, the Company would expect net benefits of $109 million if the gas price was 10% lower than the low no carbon case. This $127M reduction is calculated by multiplying the $236M by the gas price reduction ratio of 10/18.5.

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