2015 ITP10 Scope

Approved by ESWG: 03/24/2014
Approved by TWG: 03/28/2014

ESWG / TWG / SPP Staff

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Overview

This document presents the scope and schedule of work for the Integrated Transmission Planning (ITP) 10-Year Assessment. This document will be reviewed by the Transmission Working Group (TWG) and the Economic Studies Working Group (ESWG) beginning May 2013, with the expectation of approvals from the Market Operations and Policy Committee (MOPC) and the Board of Directors (BOD) in October 2013. The assessment begins in July 2013 and is an 18-month study scheduled to be finalized in January 2015.

Objective

The 2015 ITP 10-Year Assessment (ITP10) is a value-based planning approach that will analyze the 10-year out Transmission System and identify 100 kV and above solutions to needs stemming from multiple sources: (a) needs identified in the reliability analysis of the 69 kV and above system, (b) needs identified to meet projected renewable policy mandates and goals, (c) needs arising from transmission system congestion, and (d) needs arising from instability of the transmission system.

The 2015 ITP10 will be utilized in integrating the 2013 ITP20 with the 100 kV and above facilities to incorporate such needs as the following: a) resolving criteria violations; b) mitigating known or foreseen congestion; c) meeting projected policy mandates and goals; d) improving access to markets; d) the staging of transmission expansion. This assessment is not intended to review each consecutive year in the planning horizon, but only the horizon year.

Stakeholder Process

Working Group Involvement

The 2015 ITP10 will be vetted through the SPP working groups. The ESWG will oversee the economic portions of the 2015 ITP10 and all related data and assumptions. The TWG will oversee the reliability portions of the 2015 ITP10 and all related data and assumptions. The following items will be discussed at the respective working groups:

Regional Cost Allocation Review Rask Force (RARTF)

A regional cost allocation review will be performed in conjunction with the ITP10 process to identify potential project solutions to mitigate Benefit inequities which exist in certain zones.

Transmission Working Group (TWG), Model Development Working Group (MDWG)

The TWG and/or the MDWG will be responsible for reviewing the data and results for the following items:

1) Scope
2) Futures - Approval
3) Load Forecast – Peak Demand
4) Steady State Models
5) Constraint Review
6) Reliability Assessment
7) Stability Assessment
8) Transmission Plan Development
9) Benefit Metrics
10) Report

Economic Studies Working Group (ESWG)

The ESWG will be responsible for reviewing the data and results for the following items:

1) Scope
2) Futures – Development and Approval
3) Policy Survey
4) Load Forecast - Energy
5) Generator Review

6) Resource Plan and Siting
7) Economic Modeling Assumptions
8) Policy Assessment
9) Economic Assessment
10) Transmission Plan Development
11) Benefit Metrics
12) Sensitivities
13) Report

Markets and Operations Policy Committee (MOPC)

The MOPC will be sought for endorsement of the following items:

1) Scope
2) Futures
3) Policy-Driven Decisions
4) Metrics
5) Report

Strategic Planning Committee (SPC)

The SPC will be sought for endorsement of the following items:

1) Futures

Seams Steering Committee (SSC)

The SSC will be responsible for the review of the following item:

1) Seams Impacts

Regional State Committee (RSC)

The RSC will be responsible for the following items:

1) Approve Cost Allocation
2) Review the final Report and endorse as appropriate

Board of Directors (BOD)

The BOD will approve the following items:

1) Transmission Plan

2) Cost and Benefit Allocation

3) Report

The final 2015 ITP10 Report will be approved by the BOD.

Stakeholder Reviews

The following is a list of reviews to be provided by stakeholders during the 2015 ITP10 study:

Load Forecast Review

Projected peak load per area for the year 2019 and 2024 will be submitted by the modeling contacts for the development of a peak 2019 and 2024 model. Energy per area for 2019 and 2024 will be obtained from publicly available sources and reviewed and updated by stakeholders. Stakeholders will review projected peak load and energy per area. Peak load and energy will also be identified for load serving entities within SPP RTO areas (for example, Hastings Utilities and City of Grand Island load will be reviewed by NPPD).

Policy Survey

Stakeholders will provide feedback through a survey, conducted by the ESWG, on current and planned renewable generation plants.

Generation Resource Plan Review

ESWG will review the data for all generators added to the model as part of the 2015 ITP10 resource plan. This will include conventional and renewable generation. The review will focus on the siting and capacity of new units. For conventional generation, the zonal demand and capacity figures will be provided, as well as expected capacity margins for 2024. For renewable generation, the siting, capacity, and average capacity factor of each new resource will be provided. This will include resources identified as a part of the Policy Survey and may include renewable resources identified by the resource planning software.

Economic Model Review

ESWG will be provided with model data indicating generators and the parameters used in the economic model. Non-confidential parameters such as maximum capacity, ramp rates, O&M costs, etc. will be provided for review. For confidential parameters, such as heat rates, publicly available data will be utilized. However, resource owners may modify the publicly available data to more accurately model their generator's characteristics as appropriate.

Constraint Assessment Review

A list of constraints will be developed to be used in the economic dispatch, as detailed in the Constraint Review Section below. The constraints will be provided to the TWG for review; they will approve the final list of constraints to use, as well as the associated constraint ratings.

Power Flow Model Review

TWG and MDWG will review the economically-dispatched power flow models and provide feedback. The review will focus on the reactive needs.

Project Development Request

Stakeholders will be asked to provide suggestions on projects they believe should be analyzed in the study. All stakeholder-submitted project requests will be analyzed to assess the project's potential to meet needs. This includes reliability, economic, and policy needs as detailed in the Analysis Section of this document.

Study Process

1. The futures will be selected and assumptions refined through the various stakeholder groups (ESWG, TWG, MOPC, RSC).

2. The ESWG will oversee the development of the economic models that incorporate the assumptions developed in step #1 above, including review of data and results. Similarly, the TWG will oversee the development of the power flow and stability models used in this analysis, including a summer peak case and an off peak case. These will be developed through the existing SPP Planning Model Process via the MDWG.

3. Constraints will be developed through the identification of congested facilities and by performing transfer analyses. All constraints will be 100 kV and above facilities for 100 kV and above facility outages within SPP and first tier neighbor systems.

4. Staff will perform an initial AC analysis using applicable NERC Reliability Standards and SPP Criteria on power flow models that represent the applicable load profiles and generation dispatch associated with each future. The assessments will be limited to the planning horizon year. All facilities 69 kV and above in the models will be monitored within SPP and the first-tier for this analysis as a means to determine 100 kV and above solutions for SPP to the problems identified. The TWG will review the results.

5. Concurrently, an economic assessment will be performed to analyze congested facilities on the SPP Transmission System. This will be done using a security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) model over 8,784 consecutive hours.

6. 100 kV and above solutions to criteria violations, policy requirements, and/or congested facilities will be identified with input from stakeholders and coordinated as applicable with SPP neighbors. Staff will request suggestions for solutions from stakeholders and perform a preliminary assessment of benefits for these projects. During this phase, Staff will coordinate solutions with the AG and GI Study processes to best accommodate the high-demand areas for the SPP transmission system footprint. Issues identified that are not resolved with 100 kV and above solutions will be deferred to ITP Near-Term Assessments for resolution.

7. A check will be performed to determine if projects identified in the 2013 ITP20 will eliminate or defer any projects identified in the 2015 ITP10. This check will be performed by replacing lower voltage solutions with the higher voltage solutions identified in the 2013 ITP20 and re-running the economic and contingency analysis. The economic analysis will include calculating benefit and cost for each alternative.

8. A follow-up analysis will be performed by Staff repeating the steps above on the identified solutions to validate the solutions and check for any additional criteria violations and/or congested facilities that may have been created.

9. A sensitivity analysis will be performed on the recommended portfolio to assess how versatile the plan is in handling a range of uncertainties.

10. Benefit metrics will be calculated for the recommended portfolio on each future.

11. A 40-year financial analysis will be conducted on the recommended portfolio.

12. Stability analyses will be conducted on the recommended portfolio to determine if voltage stability requirements for the region are met. Dynamic stability analysis will be performed on the Business As Usual Future. A wind transfer voltage stability analysis will be performed on each future.

Data inputs

Economic

The analysis for the 2015 ITP10 will utilize engineering models to facilitate the development of long range transmission plans. One set of models will be the economic models used to produce a market based resource dispatch used in the analysis. These models require certain assumptions regarding generation resources, parameters, and locations (detailed in the following sections). The output of these models will allow engineers to identify the appropriate transmission additions needed from an economic perspective. This output can also be used to determine deliverability of the resources to market used in the analysis.

The major assumptions needed to construct the economic models are detailed below and contain, but are not limited to: market structure, load forecasts, resource forecasts and parameters, transmission topology, renewable assumptions, fuel pricing and availability, etc. Once these assumptions are input into the model, it will perform a security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED).

The following sections detail the parameters to be used in the economic portion of modeling.

Market Structure

SPP anticipates implementing its Integrated Marketplace and Consolidated Balancing Authority (CBA) in March 2014. The Integrated Marketplace and CBA will be baseline assumptions for the analysis.

Futures

Future 1: Business as Usual

This future will include all statutory/regulatory renewable mandates and goals as well as other energy or capacity as identified in the policy survey, load growth projected by load serving entities through the MDWG model development process, and the impacts of existing regulations. This future assumes no major changes to policies that are currently in place.

Future 2: Decreased Base Load Capacity

This future will consider factors that could drive a reduction in existing generation. It will include all assumptions from the Business as Usual future with a decrease in existing base load generation capacity. This future will retire coal units less than 200 MW, reduce hydro capacity 20% across the board, and utilize the Palmer Drought Severity Index for an average of August 1934 and August 2012 to simulate a reduction in existing capacity affected by drought conditions: 10% under moderate, 15% under severe, and 20% under extreme. These target reductions may be adjusted based on locational and operational characteristics within each zone.

Load Forecasts

The study will require load forecasts for SPP members and non-members within the SPP footprint, as well as areas outside of the SPP footprint, for the year 2019 and 2024. SPP Staff queries its

members through the MDWG for applicable load forecasts to use in each of the zones for the modeling footprint. The base model will also include additional load expected in the SPP region. This load will include a 50/50 forecast from the High Priority Incremental Load Study (HPILS) and will be vetted through the ESWG and the TWG. Energy forecasts will be provided by the ESWG and other contacts. Load shapes will be obtained from publicly available data for the typical load projections and requested from stakeholders for the HIPILS loads. Load shapes will be benchmarked as detailed in the Benchmarking Section.

For load forecasts outside of the SPP footprint, SPP will request load forecasts from SPP tier 1 neighbors. If data is not provided, publicly available data will be utilized as the source of the load forecasts, where available. If unavailable, publicly available information on projected load growth will be extrapolated to develop a representation for load expected in the study timeframe.

Resource Plan

A generation resource plan for 2019 and 2024 will be developed for use in the study for each future. This resource plan will include both renewable and conventional generation. Additionally, new renewable and conventional generation resources will be sited as detailed below.

Each SPP RTO load serving member must meet the current 12% capacity margin requirement outlined in SPP Criteria 2.1.9. The siting of new generation in the resource plan will target a 12% capacity margin for each zone. Capacity needs will be identified for each future for 2019 and 2024.

Renewable generation, for the purposes of this study, includes hydro, wind, solar, and bio-fuel. Designated renewable resources will be identified through the policy survey. Additional renewables will be included in the plans, as needed, to meet the renewable projections, as supplied by the Policy Survey. Additional renewables identified by the resource planning software may also be included. The renewable ownership designations will be reviewed by stakeholders and posted on SPP.org.

SPP tier 1 neighbors will be provided the opportunity to provide feedback and input into the generation resource plan for their area.

System Topology

The focus of the Study is to develop a comprehensive, flexible, and cost-effective transmission expansion plan to meet the requirements of the SPP footprint under various futures.

Power flow models will be required for the Study for both the economic and reliability assessments. The starting point of these power flow models will be the latest MDWG information from Model on Demand™, which includes the current projects from the latest SPP Transmission Expansion Plan (STEP). These power flow models will serve as an input into the economic (production) modeling program to develop a market based economic dispatch for the system.

Two new DC interconnections, the Tres Amigas DC Tie and the Clean Line Plains & Eastern project, will be included in the models for sensitivity analysis only.

Economic Model Generation Parameters

The generation parameters (Startup cost, operating costs, Min/Max Operating Levels, etc.) will be updated by the ESWG as part of the economic model review.

Renewables

Renewable generation, primarily wind, hydro, and solar, operate as energy resources that will require the development of hourly generation profiles for individual plants based on historical data or modeled time-series wind speed datasets. These generation profiles will be time-synchronized with coincident historical load shapes. The economic dispatch model will attempt to realistically model renewable generation curtailment, based on expected market conditions and reliability requirements. A curtailment price consistent with the variable O&M cost will be used to simulate the behavior of the wind generation within the Security Constrained Economic Dispatch (SCED). The ESWG will review the behavior and costs of the renewable generation against appropriate benchmarks.

Siting

The expected location of future generation will be considered in areas with appropriate potential. These sites will be further developed and refined as a subset of those selected in the 2013 ITP20 study, as appropriate for the futures of this study. SPP will request that tier 1 neighbors provide siting based on SPP's identification of capacity needs from the resource plan. If siting is not provided, SPP will site new generation.

DC Ties and Lines

DC ties and lines connect SPP to the WECC and ERCOT and Eastern Interconnect systems. Confirmed long-term firm transmission service will be used as a basis for modeling the flow levels of DC ties and lines. Hourly profiles will be developed based on 3-year historical flows on the DC facilities, limited to boundaries of existing long-term firm service commitments. The hourly profiles will be vetted with ESWG and TWG. The cost of energy purchases and sales across the DC ties will be calculated using the hourly average zonal generation locational marginal price of each utility owner multiplied by their ownership share of the output. No curtailment price will be assumed for the long-term firm service profile. For those DC ties or lines with no confirmed long-term firm transmission service, Staff will model no flow across the DC ties and lines.

Fuel Prices

Fuel forecasts will be utilized in the resource planning, production cost modeling, and benefit metric calculations. Fuel prices for coal, oil, and uranium, including transportation costs, will be forecasted for the 2024 study year based upon the latest Ventyx Reference Case available at the onset of the study. NYMEX futures will be utilized for natural gas prices, out to the latest year for which the futures are available. For natural gas prices beyond this year, growth rates from the DOE Annual Energy Outlook will be utilized. The specific NYMEX and DOE numbers will be developed during the resource planning phase of the study and then locked down for the remainder of the study.

Environmental Policy

Emission price forecasts for SO_2, NO_X, and CO_2 for the 2024 study year will be based upon the latest Ventyx Reference Case data available at the onset of the study.

Policy Survey

A policy survey will be administered by the ESWG and will be used by stakeholders to provide assumptions regarding specific renewables information. The previous renewables surveys will be used as a reference for development of the current survey. The survey will contain, at a minimum, the following information:

- Name, zone, and capacity for all specific renewable sites that are in-service or expected to be in-service by the end of 2014;
- Renewable energy totals for 2024 and 2019 based on state and utility mandates, goals, and other utility company policy;

For all renewable sites in the models, the renewable energy output for each hour of the year will be based on the maximum capacity provided in the survey. Capacity factors and hourly profiles will be based on expected or historical behavior. Calculations for policy requirements will incorporate stakeholder specific inputs, and capacity factors for wind used in the Study will be based on NREL wind profiles that correspond to a similar location as the wind site and are based on historical weather patterns. For new wind sited to meet the requirements of the Policy Survey and resource plan, a 15% increase will be applied to the existing capacity factors being utilized for each of the NREL sites.

Hurdle Rates

Hurdle rates will be utilized in the economic model between SPP and neighboring systems to help keep imports and exports at a reasonable exchange levels. Hurdle rates for imports and exports between SPP and other entities will be determined during the benchmarking process.

Hurdle rates between non-SPP entities will be set as needed to model minimal and reasonable exchange between these entities.

Benchmarking

After all assumptions and data are included in the economic model, it will be benchmarked against historical system behavior. This benchmarking will be used to assess the reasonability of the simulations.

In order to complete the 2015 ITP10 benchmarking effort, a model will be developed based upon the year 2013. Simulation results from that economic model will be compared with historical statistics and measurements from the SPP real time data, NERC data, and the Energy Information Administration data.

The ESWG will review the benchmarking data as part of the model review process. Specific benchmarks will include some or all of the following: capacity factor by unit type, generation by unit category, maintenance outages, load shapes, renewable generation profiles, operating, and spinning reserve levels, coal transportation costs, system Locational Marginal Prices (LMPs), flowgate loading, production costs, generation dispatch order, and zonal purchases and sales.

Steady State

Being that SPP will implement its Integrated Marketplace and CBA in 2014, power flow models with a market dispatch under coincident peak load and off peak load will be developed.

Steady state analysis will be conducted using output from the economic models as a starting reference for load and generation dispatch. These models will be utilized in additional engineering tools in order to conduct an assessment to determine the SPP system's voltage and thermal impacts. This steady state assessment is detailed in sections below.

Load

The load density and distribution for the steady state analysis will be reviewed by the MDWG. Resource obligations will be determined for the footprint taking into consideration what load is industrial, non-scalable type loads and which load grows over time. The MDWG, TWG, and ESWG provide collaborative feedback into the determination of this impact. The load used in the steady state analysis will be the same as that used in the economic model as described in Section: System Topology.

Generation Resources

The generating resources determined through Section A.III: Resource Plan will be added to the power flow. Each future will contain a different subset of generation resources and correspond to a unique power flow case. These generating resources will be reviewed by the ESWG and will correspond to the economic analysis conducted for the Study.

Steady-State System Topology

The topology used in the steady state analysis will be the same as that used in the economic model as described in Section: System Topology.

Exports/Imports to First Tier

The exports/imports used in the steady state analysis between SPP and neighboring AC systems will be determined by the economic dispatch model. Exports and imports between DC interconnections will be based on historical hourly scheduling of long-term firm transmission service. This economic exchange of energy between neighboring systems will be modeled for the steady state analysis.

Market Dispatch

The economic models will be used to determine hourly load profiles and generation dispatch for the steady state analysis. The generation dispatch and corresponding hourly profiles will be mapped from the economic model to the reliability power flow model.

Analysis

Define Constraints

To identify which constraints are applicable in 2024, Staff will begin by reviewing the existing NERC Book of Flowgates (BoF) to determine additions or deletions from the list of constraints (event file) for the economic model. Staff will perform additional analysis using Power Analytics and Trading Tool (PAT) to identify the top constraints by congestion costs (average shadow price times the number of constrained hours) on the system for 8,784 hours. These additional constraints will be reviewed and approved by TWG. The following items will be considered in the analysis:

- The initial constraint list will be the then-current BoF
- Constraints studies will be run over 8,784 hours (1 year)
- This analysis will use the 2024 economic model(s) for each future
- Contingencies 100 kV and above in SPP and first-tier
- Monitored elements 100 kV and above in SPP and first-tier
- Unless other information is available, each constraint's rating will be selected based upon the applicable Rating A (normal rating) or Rating B (emergency rating) in the power flow model.

Needs Assessments

The reliability, policy, and economic needs of the system will be identified in each future in order to develop a transmission portfolio for each future. Each analysis will be performed in parallel to determine all needs across the system in 2024. All needs indentified in the assessments below will be evaluated by Staff for potential consideration in the interregional planning process pursuant to the requirements of Order 1000.

Economic Assessment

The economic needs of the system will be identified in each future in order to develop a portfolio for each future. All of the system needs will be identified through the use of a SCUC & SCED simulation that accounts for 8,784 hours representing each hour of the year 2024.

The SCED will determine nodal Locational Marginal Prices (LMPs) while dispatching the generation economically. The LMPs, among other cost components, reflect the congestion occurring on the power grid's binding constraints. System congestion will be identified in each of the 8,784 hours. A list of binding constraints will be developed for each future and ranked based upon the average shadow price associated with each constraint. The top twenty constraints based upon this ranking will be identified as economic needs. This list may be modified, subject to ESWG review and approval.

Policy Assessment

The policy needs of the system will also be identified for each future in order to develop a portfolio for each future. All of the system needs will be identified through the use of a SCUC & SCED simulation that accounts for 8,784 hours representing each hour of the year 2024. Renewable generation may experience the effects of congestion and be curtailed by the SCED. Shortfall in the achievement of the renewable requirements of each future due to this curtailment will be identified. Renewable resources that experience an annual energy output of less than the statutory/regulatory mandate or goal will be identified as policy needs. The required energy is based on maximum capacity, capacity factor, and generation profile.

Steady State Assessment

The steady state assessment will use 2024 summer peak and high wind with low load (off peak) models based on a market dispatch. Each future will be evaluated for the same peak and off peak hours. An N-1 contingency analysis will be conducted on each future for the peak and off peak cases. All SPP and first tier facilities 69 kV and above will be monitored for this analysis in development of 100 kV and above solutions.

The non-converged contingencies will be reviewed.

Stability Assessment

Dynamic stability analysis will be conducted on the final recommended portfolio for the Business as Usual future to assess transient voltage recovery. It will be conducted on the off peak model simulating the 2013 TPL Category B and C contingencies identified by members and additional contingencies identified by Staff through the Fast Fault Screening tool. TWG will review and approve Staff identified contingencies for further analysis.

A voltage stability assessment will be conducted on each future using the recommended final portfolio to assess the transfer limit (MW) due to transfer of wind west to east across the SPP footprint. These must be determined by examining voltage performance during power transfer into a load area or across an interface. The stability assessment consists of a wind dispatch analysis to determine if the dispatched wind generation in the 2015 ITP10 2024 summer peak models in all futures can be dispatched without the occurrence of voltage collapse or thermal violations.

Solution Development

Staff will solicit stakeholders for possible solutions to the needs. A pool of possible solutions will be used to mitigate the economic, reliability, and policy needs in creating the 2015 ITP10 transmission plan. This pool of solutions will come from transmission service studies, generation interconnection studies, previous ITP studies, and stakeholder input. Solutions developed could meet more than one need (i.e. economic, policy, and/or reliability needs) and will be classified as project types based on the criteria outlined below. To the extent benefit to cost deficient zones are identified as a result of the Regional Cost Allocation Review, remedies will be evaluated and recommended by Staff, in coordination with the deficient zones and appropriate stakeholder groups, as part of the 2015 ITP10 analysis as appropriate.

Based on the criteria below, Staff will develop a plan for each future. Staff will then consolidate the projects from each future into a recommended plan.

Economic Project Solutions

Economic projects will be developed and evaluated based upon how well they mitigate congestion. Any economic project with a one-year B/C ratio of 0.9 or greater will be included for further evaluation.

Economic seams projects will be initially evaluated and considered under the assumption that the project would be cost shared with an SPP neighbor, with SPP paying for 80% of the cost and the neighbor paying 20% of the cost. As the evaluation progresses and the SPP neighbor identifies the level with which the transmission project benefits them, then the cost percentages should be updated to a more accurate reflection of the benefit distribution.

Policy Project Solutions

Policy projects will be developed and evaluated based upon how well they mitigate curtailment of renewable energy required by the regulatory/statutory mandates and goals as defined by the 2015 ITP10 policy survey. Any policy project that helps to mitigate curtailment of renewable requirements will be included for further evaluation.

Reliability Project Solutions

Reliability projects will be developed and evaluated based upon how well they mitigate member criteria violations for the peak and off peak hours.

Interregional Considerations

Seams projects will be considered as part of the 2015 ITP10 study and expansion plan as potential solutions, and SPP will collaborate with neighboring entities regarding the identified needs, benefits, potential solutions, and costs. For the neighbors that SPP has an agreement with, joint coordination will be done in accordance with that agreement.

Final Recommended Portfolio

Reliability, policy, and economic solutions will be grouped together and refined to create a portfolio for each future. The grouping of projects will be evaluated for redundancies. If, for example, a reliability project is similar to a policy project, the two projects will be evaluated to see which project meets both the reliability need and the policy need in the most cost effective way, while the other project is then discarded.The final portfolio for each future will be consolidated into a single portfolio. The consolidation will be based on the following criteria: Economic projects with a 1-year B/C ratio greater than 0.9 in Future 1 will be included in the consolidated portfolio. Economic projects with a 1-year B/C ratio greater than 0.7 in Future 1, but that also have a 1-year B/C ratio greater than 0.9 in Future 2 will also be included in the consolidated portfolio.

Policy projects will be included in the consolidated portfolio if they meet a policy need in Future 1.

Reliability projects will be included in the consolidated portfolio if they mitigate a thermal/voltage violation in Future 1. A Future 2 reliability project will be included if it mitigates a thermal violation in Future 2 and mitigates loading above a 90% threshold in Future 1. A Future 2 project that mitigates a voltage limit violation in Future 2 and voltage below 0.92 pu in Future 1will also be

included in the consolidated portfolio. Thermal and voltage violations are defined by SPP Criteria and local Transmission Owner criteria.

Additionally, projects with significant potential value may be selected to be part of the consolidated portfolio. SPP Staff can request additional projects be included in the consolidated portfolio, but they will be required to present the project and justification to the appropriate stakeholder groups and obtain approval from those groups.

Forty-Year Financial Analysis

The 2015 ITP10 shall assess the cost effectiveness of the recommended portfolio over a forty-year time horizon in accordance with Section III.3.c of Attachment O of the SPP OATT. To estimate the benefits over 40 years, Adjusted Production Cost (APC) savings will be calculated for the two model years developed, 2019 and 2024. The slope between the selected points will be used to extrapolate the benefits beyond 2024 over a 40 year timeframe. The costs will be calculated using the formula for Annual Transmission Revenue Requirement (ATRR). The total benefits and costs will be reported in net present value (NPV) dollars.

Benefit and impact calculations will be made on a Regional, Zonal, and State basis. State values will be extrapolated from the zonal costs and benefits. Many zones are only in one state. For those zones that are only in one state, their full portion of both costs and benefits will be allocated to the state. For zones crossing state borders, their portion of both costs and benefits will be allocated to each state based on their percentage of load that is in each state.

Net benefits and B/C ratios will be calculated based on NPV benefit and NPV cost and will be reported based on present dollars (2014).

Benefit Metric Development and Usage

The metrics used to measure the value of the final portfolio in the 2015 ITP10 are identified here and will be vetted with the ESWG. These metrics will be used to measure the value of the final consolidated portfolio on each Future.

Metric Description
APC Savings
Savings Due to Lower Ancillary Service Needs and Production Costs
Avoided or Delayed Reliability Projects
Marginal Energy Losses
Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
Reduction of Emissions Rates and Values
Public Policy Benefits
Assumed Benefit of Mandated Reliability Projects

Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues

Table 1: Monetized Cost Benefit Metrics for 2015 ITP10

To the extent that any adjustments or changes to Benefit Metrics are recommended by the Regional Allocation Review Task Force (RARTF), these changes will be considered by the ESWG and TWG.

Sensitivities

Sensitivities will be conducted on the final recommended portfolio for the Business as Usual Future to assess how versatile the plan is in handling a range of uncertainties. Economic analysis will be performed for the sensitivities. The following sensitivities will be performed:

- Natural Gas Price
- Demand levels
- Tres Amigas and Clean Line Plains & Eastern
- Increased Input Prices

Specifics of the DC project sensitivities will be developed and approved by the ESWG.

An Increased Input Prices sensitivity will be performed using the Business as Usual model (resource/siting plan). It will consider a $36/ton carbon tax and a threefold increase of natural gas prices. As a result of increased input prices, it will also consider a reduction in the rate of load growth of 1% per year. This sensitivity will test for two of the benefit metrics; adjusted production cost and reduction of emission rates and values.

The sensitivities will be used to measure the viability of the proposed transmission plan that is produced through the 2015 ITP10. These sensitivities will not be used to develop the transmission projects or filter out projects.

Staging

A project implementation plan will be developed for the final recommended portfolio. The final portfolio 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 years 2019 and 2024. This section is broken into two parts: one for projects classified to meet one set of needs (i.e. economic, policy, or reliability needs); one for projects meeting multiple needs.

Single Project Classification

For economic projects in Future 1, Staff will stage projects based on linear interpolation of B/C ratios from 2019 to 2024 with consideration of lead times. For economic projects in Future 2, Staff will stage them with a 2024 need date.

For policy projects, Staff will stage projects in order to meet the renewable requirements.

For reliability projects in Future 1, Staff will stage projects based on linear interpolation of thermal loadings from 2019 to 2024. All other reliability projects in Future 1 will be staged with a 2024 need date. For reliability projects in Future 2, Staff will stage them with a 2024 need date.

Multiple Project Classification

If a project is classified as more than solely economic, policy, or reliability project, the project will be staged to meet the earliest need date established through the Single Project Classification Section with a requirement that for economic projects, the one-year B/C ratio threshold crosses 1.0.

Reactive Needs

If any 300 kV and above upgrades are identified as solutions in the portfolio, line-end reactive requirements analysis will be performed for the new transmission lines greater than 300 kV system to provide an indicative amount of reactor needs before design level studies are completed.

Final Reliability Assessment

A steady state N-1 contingency analysis will be conducted to identify any remaining outstanding issues on the final recommended portfolio.

Cost Estimates

The cost estimates used for projects that are tested in the initial project development phase will be Conceptual Estimates as defined by the SPP Business Practice 7060. The Conceptual Estimates will be developed by Staff and utilize standardized estimates and multipliers that are based on historical data. Projects that pass the initial screening phase will be designated for Study Estimates as defined by Business Practice 7060.

A Study Estimate will be prepared by the designated TO(s) for non-competitive upgrades and by Staff for competitive upgrades by completing a Standardized Cost Estimate Reporting Template (SCERT) for all upgrades that are required to complete that project. The Study Estimate will provide a more refined cost estimate for potential project approval. For all Study Estimates, Staff will provide TO's a minimum of six weeks from the date of request before the estimate is due.

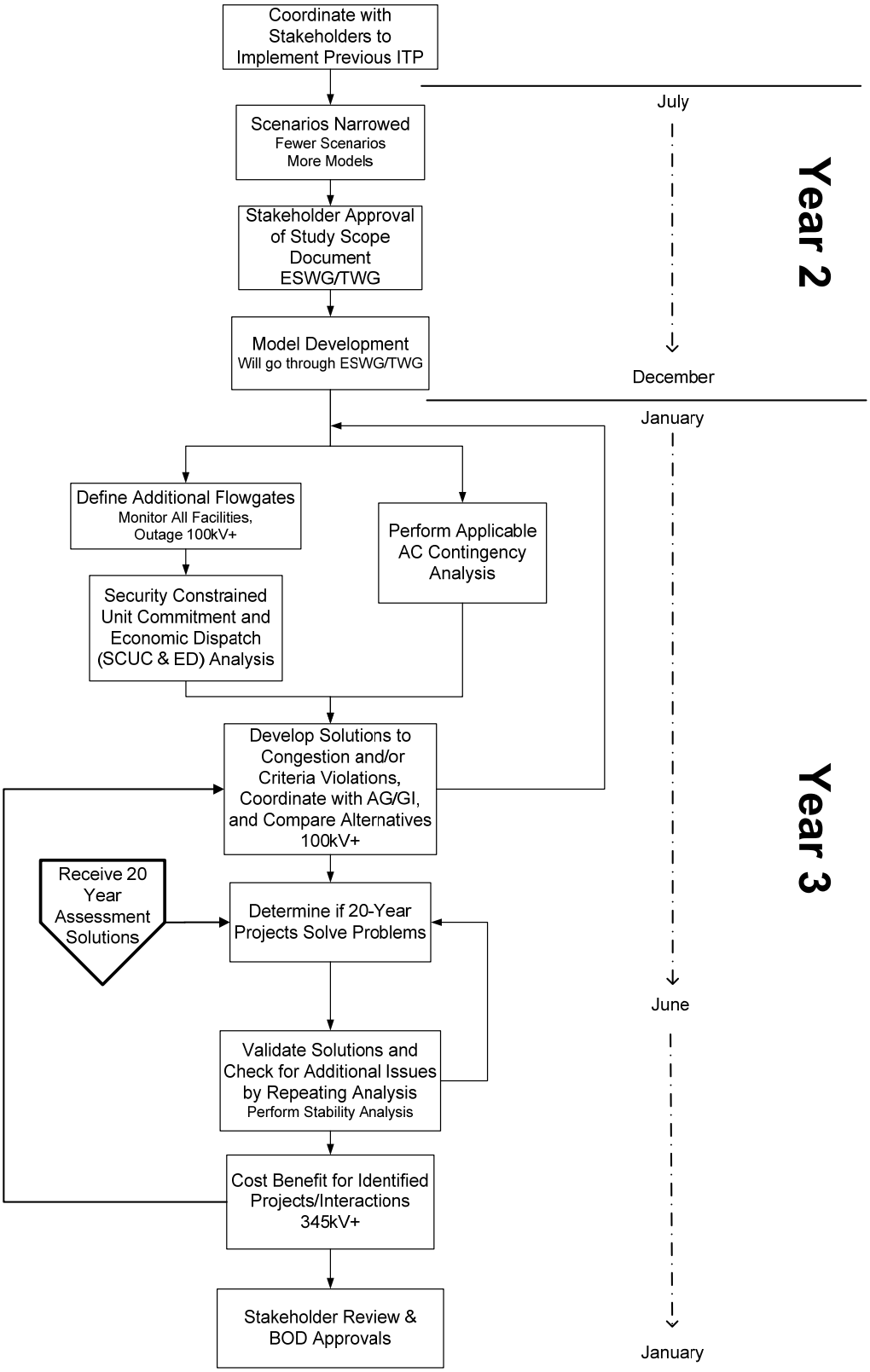
Timeline

The 2015 ITP10 will generally follow the process flow below beginning in July 2013 with final results in January 2015. The estimated timeline is as follows:

2015 ITP10	Group(s) to review/endorse	Start Date	Completion Date
Futures & Scope	ESWG, TWG	April 2013	October 2013
Policy Survey	ESWG	May 2013	August 2013
Load Forecast and Generation Review	ESWG, TWG	May 2013	August 2013
Resource Plans Development & Review	ESWG	August 2013	October 2013
Siting Plan	ESWG	September 2013	October 2013
Economic Model Development & Review	ESWG	May 2013	December 2013
Model Benchmarking	ESWG	January 2014	
Constraint Review	TWG	November 2013	January 2014
Economically-dispatched Powerflow Model Development & Review	TWG	January 2014	April 2014
Reliability, Policy, Economic Needs Assessment	ESWG, TWG	February 2014	April 2014
Finalize benefits metrics and allocation methods for ITP10 portfolio analysis	ESWG, TWG	April 2014	April 2014
Project Development Request	ESWG, TWG	April 2014	May 2014
Project Grouping	ESWG, TWG	June 2014	June 2014
Final Recommended Portfolio	ESWG, TWG	June 2014	July 2014
Project Staging	ESWG, TWG	July 2014	August 2014
Sensitivities Conducted	ESWG	July 2014	September 2014
Final Benefit Metrics Calculations	ESWG	July 2014	September 2014
Stability Analyses	TWG	May 2014	September 2014
Review draft report with recommended solutions	ESWG, TWG	July 2014	September 2014
	MOPC	October 2014	
Final report with recommended solutions	ESWG, TWG	November 2014	December 2014
	RSC	January 2015	

	MOPC	
	BOD	

10-Year Assessment Process (Initiated Every 3 Years)



Deliverables

Final Report and Recommended Portfolio

The results from the 2015 ITP10 will be compiled into a report detailing the findings and recommendations of SPP Staff. The report will include a project list identifying each upgrade. This report will also be incorporated into the 2015 STEP Report.

Staging and Timing of Project Implementation

A project implementation plan will be developed for the recommended transmission plan. The final plan 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. Each element will have at least one of the following justifications: policy, economic or reliability justification. NTCs/NTC-Cs will be issued for the 2015 ITP10 plan elements in accordance with the Tariff, Attachment O, Section VI and SPP written procedures (see Business Practice 7060[1]).

Changes in Process and Assumptions

In order to protect against changes in process and assumptions that could present a significant risk to the completion of the 2015 ITP10, any such changes must be vetted. If a stakeholder group votes on any process steps or assumptions to be used in the study, those assumptions will be used for the 2015 ITP10. Changes to process or assumptions recommended by stakeholders must be approved by the appropriate stakeholder group(s) and the MOPC. This process will allow for changes if they are deemed necessary and critical to the ITP, while also ensuring that changes, and the risks and benefits of those changes, will be fully vetted and discussed.

[1] SPP.org > Org Groups > Access SPP's Governing Documents > OATT Business Practices