Comparison of Transmission Reliability Planning Studies of ISO/RTOs in the U.S.

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Chapter 1: Introduction and Objective

The Energy Policy Act of 1992 and the landmark FERC Orders 888 and 889 de-regulated the wholesale power markets, and required fair and non-discriminatory access to the transmission system. Recognizing the vision of increasing market competition, Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) were created to operate regional power systems, implement wholesale markets, and ensure open access to transmission.

A key responsibility of the ISOs/RTOs is to conduct system planning such that the grid can be operated reliably. The scope of ISO/RTO responsibility is thus very wide – covering operational aspects from a time frame of seconds to planning studies in the multi-year time horizon.

Transmission system reliability and planning encompasses various aspects, including:

- Transmission security: The ability to continue operating reliably following sudden and unexpected contingencies
- Transmission adequacy: Having sufficient transmission capacity to move power across key interfaces and corridors in the system
- Resource adequacy: Maintaining transmission or generation capacity to meet customer needs in spite of scheduled and unscheduled outages

This report reviews and compares aspects of the transmission planning procedures of the ISOs and RTOs in the US. It is not a comprehensive review of the planning procedures, but rather focuses on the studies that assess the need for transmission improvements and identify potential solutions. NERC requires that planners use a stressed power flow case for the reliability needs assessment, but the approach used to develop the stressed cases vary from region to region. This report summarizes the assumptions and approach the ISOs and RTOs use in developing their base cases and compares them to that of ISO New England (ISO-NE).

The content of the report is based on publically available manuals, studies and reports, and on surveys of selected ISOs/RTOs. It does not represent the opinions, viewpoints, or recommendations of ICF or the authors.

The rest of the report outlines the similarities and differences in planning practices of other ISOs and RTOs relative to that of ISO-NE. Chapter 2 reviews ISO-NE's planning procedure. Chapters 3 through 8 review the planning procedures of the other six ISO/RTOs – the California Independent System Operator (CAISO), the Electric Reliability Council of Texas (ERCOT), the New York Independent System Operator (NYISO), PJM Interconnection, LLC (PJM), the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP). The Appendix is a table that summarizes the key features of the planning processes of all the ISO/RTOs.

Table 1 Key similarities and differences of planning practices of ISO-NE with other ISO/RTOs

	ISO-NE approach	Similarities	Differences
Source of power flow case	• ISO-NE uses Multi-region Modeling Working Group (MMWG) database for developing the power flow case.	• MISO, PJM and SPP use a power flow case derived primarily from the MMWG database.	• CAISO, ERCOT and NYISO develop power flow cases primarily from internal and regional stakeholders.
Summary of base and sensitivity cases developed and analyzed	• ISO-NE develops multiple base cases for a study area. • ISO-NE conducts sensitivity analyses to assess the impact of changes that could occur within the planning horizon.	• Most ISO/RTOs develop multiple base cases to represent intra-year and inter-year system conditions. • CAISO and PJM develop multiple base cases for a study area. • Additional scenarios are developed to evaluate future system conditions. Examples include different load growth, generation retirement, and transmission assumptions. • Additional sensitivity cases are developed to assess the impact of changes that could occur within the planning horizon. Examples include 90/10 load vs. 50/50 load or change in type of fuel and prices.	• MISO has additional cases involving wind penetration levels (not implemented in other ISO/RTOs) • SPP implements additional cases involving certain dispatch assumptions (such as a region-wide balancing area or inter-balancing areas flow assumptions). • PJM performs scenario analysis to assess the impact of variations in drivers such as regulatory initiatives and generator operational performance. • Under their long-term transmission planning processes, ERCOT, MISO and SPP develop scenarios to assess a range of futures.
Source of load data assumptions	• ISO-NE relies on its Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report) and the MMWG database for external areas	• All ISO/RTOs rely primarily on stakeholder-driven internal load forecasts for load assumptions	• ERCOT uses the higher of its internal load forecast and a load forecast developed by its Transmission Service Providers (TSP).
Source of supply resource data assumptions	• ISO-NE relies on the CELT Report.	• All ISO/RTOs rely primarily on respective stakeholder-driven internal resource studies and regional modeling databases.	• None

	ISO-NE approach	Similarities	Differences
Source of transmission topology assumptions	• ISO-NE uses topology assumptions from the Regional System Plan (RSP) for internal facilities and the MMWG for facilities external to its system.	• PJM and MISO use topology assumptions from MMWG and data furnished by member entities.	• NYISO, SPP, ERCOT use transmission topology assumptions furnished by member entities.
Baseline Load Assumptions	• ISO-NE uses 90/10 load forecast for base cases and sensitivities.	• ERCOT uses the higher of the 50/50 load forecast provided by TSPs and 90/10 weather load forecast developed by ERCOT • CAISO uses 90/10 load forecast for local area studies • PJM uses 90/10 load forecast for load deliverability studies	• Other ISO/RTOs use 50/50 load forecasts for most bulk power reliability studies. • Other ISOs/RTOs use 90/10 load for select scenarios and sensitivities. • CAISO uses 80/20 for transmission owner system studies.
Baseline supply and demand resource assumptions	• ISO-NE includes generation resources that have a capacity supply obligation or a binding contract, such as a state-sponsored Request for Proposal (RFP) or a financially binding contract.	• ISO/RTOs with a capacity market include generators that have cleared the capacity auctions. • All ISO/RTOs include renewable generation in planning cases and simulations.	• Some ISO/RTOs include existing generators and proposed generators with a firm interconnection agreement. • MISO and SPP also assume additional proxy generation to satisfy the capacity and renewables requirement. • ERCOT has provisions to place mothballed units in service for planning purposes.
Typical retirement assumptions	• ISO-NE considers generators that have submitted a Non-Price Retirement Request. Other generators considered unavailable are generators that have an accepted or a rejected Permanent De-list bid, generators	• Generators that have officially notified PJM of de-activation are modeled offline in the RTEP Base Case (after the deactivation date).	• Some ISO/RTOs assume publically announced retirements. • CAISO models retirements based on public announcements or on assumptions developed in

	ISO-NE approach	Similarities	Differences
	that have delisted in the last two rounds of capacity auctions and units that are unavailable because of special circumstances such as denial of license extensions or being physically unable to operate.		consultation with the CEC and CPUC.
Typical baseline transmission assumptions	• Transmission in New England includes facilities in-service, under construction, planned, and proposed projects. Transmission upgrades associated with the interconnection of facilities that have cleared a Forward Capacity Auction (FCA) are also included. • Transmission outside New England is based on a recent MMWG base case.	• All ISO/RTOs (incl. ISO-NE) assume transmission facilities that are in-service and under construction.	• NYISO, PJM, ERCOT and SPP include additional conditions for proposed transmission projects to qualify under baseline assumptions. These conditions include approval by an internal review board and/or approved impact studies.
Stressed Base Conditions	• ISO-NE develops a stressed case by removing the two most impactful generators that create the greatest stress on the area of study. For a specific study area ISO-NE may prepare multiple base cases with different pairs of outaged generators.	• ERCOT develops a stressed base case for its Regional Transmission Plan (RTP). ERCOT uses adjustments to generation dispatch (including dispatching mothballed resources and increasing the dispatch of variable generation resources) and load scaling outside the study area to adjust interface flows to target levels. • CAISO develops several base cases to address conditions in different study areas. Several base cases with varying load and dispatch	• Most ISO/RTOs develop base case(s) with expected generator outages. Additional scenarios and cases are developed to test the system under stressed conditions.

	ISO-NE approach	Similarities	Differences
		conditions may be used for a single study area. • PJM develops multiple base cases with generation dispatch adjusted to stress interfaces for its baseline load deliverability and generator deliverability studies.	
Base Case Interface Loading Assumptions	• Interfaces that may affect the area under study are modeled with transfer levels that cover the full range of existing capabilities. Internal and coincident (surrounding) interfaces associated with a study area are considered individually as well as in combination. Each base case is tested at different interface levels.	• CAISO stresses the interfaces into the study area. CAISO also stresses its major import and internal transfer paths to their limits. • ERCOT models the interfaces into constrained areas at their limits for local studies. • PJM develops stressed conditions on imports into its study areas for the load deliverability analysis. For the generator deliverability studies PJM turns on and ramps up generators with the most impact on transmission elements that could become overloaded. • SPP evaluates some cases to maintain projected transmission transfers between SPP legacy balancing authorities, and others to maximize all applicable confirmed long term firm transmission service. • For its local transmission planning process National Grid (within NYISO) adjusts generation dispatch	• Other ISO/RTOs model expected or projected transfer levels on the interfaces. Additional scenarios are developed to test the system under stressed transfer limits.

	ISO-NE approach	Similarities	Differences
		to stress selected portions of the transmission system.	
Steady State Contingencies tested	• ISO-NE analyzes steady state contingencies based on applicable NERC and Northeast Power Coordinating Council (NPCC) requirements (N-1; N-1-1 and extreme events contingencies). • ISO-NE analyzes extreme contingencies to determine the effect on the bulk power system. It develops plan or operating procedures to reduce the probability of occurrence or mitigate the consequences. ISO-NE does not build out the system to address the impact of extreme contingencies.	• All ISO/RTOs (including ISO-NE) analyze steady state contingencies based on applicable NERC Transmission Planning (TPL) standards (NERC TPL 001-003 or NERC TPL 001-01 to 001-03 or Category A-C). • The ISO/RTOs also assess extreme contingencies (NERC TPL 004 / TPL 001-04 or Category D) for impact. • The contingencies commonly tested include N-1, N-1-1 and G-1.	• CAISO and ERCOT test the simultaneous outage of a generator and a transmission line (G-1+N-1 contingencies).
Resolution of violations in simulations	• ISO-NE uses generation re-dispatch and reactive devices to resolve identified violations prior to the second contingency for N-1-1 assessments. • ISO-NE may also use operating guides.	• MISO, NYISO and PJM use generation re-dispatch to resolve identified violations. • PJM, MISO and SPP also rely on transmission operating guides.	• ERCOT uses prospective reliability projects to resolve the identified violations.
Measures used to eliminate violations identified in the study	• ISO-NE looks at regulated transmission solution and market responses to the identified violations. This includes investments in resources (e.g., demand-side projects, generation	• Other ISO/RTOs develop transmission solutions as a mitigation measure	• CAISO and ERCOT also consider congestion mitigation plans and special protection schemes (SPS).

	ISO-NE approach	Similarities	Differences
	and distributed generation) and elective transmission upgrades.		
Co-ordination with resource planning efforts	• ISO-NE's network topology assumption is updated to incorporate upgrades associated with resources that have cleared the FCA.	• All ISO/RTOs (including ISO-NE) use some form of resource data assumptions from the resource adequacy planning process to inform the transmission planning process.	• Not applicable

Chapter 2: Independent System Operator-New England (ISO-NE)

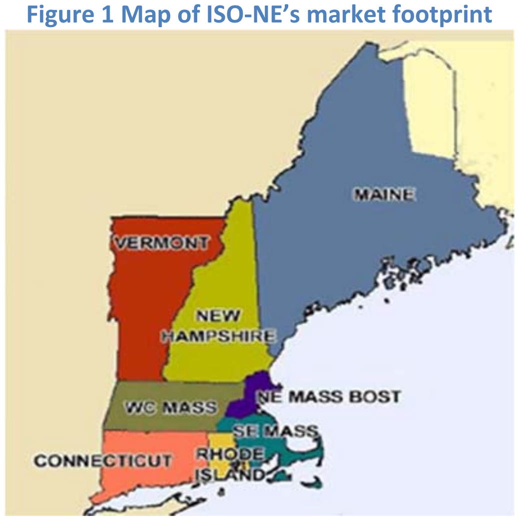
Overview

ISO New England (ISO-NE) is responsible for overseeing and administering New England's competitive wholesale electricity markets. ISO-NE serves 14 million people in the region, which includes 6.5 million households and businesses. The core reliability functions of ISO-NE includes overseeing the day-to-day operation of New England's electric power generation and transmission system; developing and administering the region's competitive wholesale electricity markets; and managing the regional power system's planning process.

Operating Footprint

ISO-NE's planning footprint covers the New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.[1] A portion of Northeastern Maine is not a part of ISO-NE. Instead it is interconnected to Canada's New Brunswick System Operator (NBSO). ISO-NE has 8,500 miles of high-voltage transmission lines (115 kV and above) with 13 transmission interconnections to power systems in New York and Eastern Canada (Quebec and New Brunswick). Since 2002, around 634 transmission projects have been placed in service across the region. An additional 201 transmission projects are planned, proposed or under construction through 2019. Currently, the installed generation capacity from 350 generators in the region is approximately 31,000 MW. Approximately 12,000 MW of generating capacity (mostly natural gas and wind) is proposed in the current interconnection queue. A map of ISO-NE's market footprint is shown in Figure 1. ISO-NE has the following eight load zones: Connecticut, Rhode Island, Southeast Massachusetts, Northeast Massachusetts (Boston area), Western Massachusetts, New Hampshire, Vermont and Maine.

Figure 1 Map of ISO-NE's market footprint



Source: FERC

[1] ISO-NE facts are based on: ISO-NE(2015). ISO-New England: Key Grid and Market Stats. Accessed online at : http://www.iso-ne.com/about/what-we-do/key-stats

Transmission Planning Process

ISO New England's transmission planning process is a stakeholder-driven process designed to evaluate and identify potential system solutions annually for a ten-year planning horizon.[2] At every stage of the process, the planning efforts are discussed with the Planning Advisory Committee (PAC). Opportunities are accorded to incorporate stakeholder comments at every step of the process ranging from the draft scope of work to the posting of final reports. The transmission planning study process begins by developing a study scope and identifying all key inputs for conducting a Needs Assessment to determine the adequacy of the transmission system, the ability of the system to operate reliably. Once the results of the Needs Assessment are made public, the potential transmission solutions are evaluated for cost effectiveness or other factors as appropriate. Under ISO-NE's planning process developed in compliance with the Federal Energy Regulatory Commission (FERC) Order 1000, ISO-NE will identify solutions through a Solution Study or a two phase competitive process depending on the timing and type of solution required. The Needs Assessment and the studies of solutions provide the basis to update ISO-NE's RSP for the latest planning cycle.

Transmission Planning Studies

ISO New England establishes reliability standards for the six-state New England region on the basis of authority granted by the FERC. Since the New England region is part of the wider Eastern Interconnect system, it is also subject to standards set by the Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Corporation (NERC). The key set of standards, criteria and assumptions are listed below:

- NERC Reliability Standards for Transmission Planning (TPL)
- NPCC Design and Operation of Bulk Power Systems (Directory 1)
- ISO-NE's Planning and Operating Procedures

As a NERC-registered Transmission Planner for the region, ISO-NE has the responsibility to implement procedures and assumptions that satisfy the intent of the NERC, NPCC, ISO-NE and Transmission Owner standards. The standards for the local system transmission planning are not prescribed by ISO-NE but instead by the Participating Transmission Owner (PTO). The standards are consistent with regional, national, and state standards, as applicable.

ISO-NE Transmission Studies

ISO-NE and its stakeholders conduct various studies to assess the capability of the transmission system. The major studies are described in Section 2 of ISO-NE's Transmission Planning Technical Guide, and include Market Efficiency upgrade studies, operational studies and reliability studies. This report focuses

[2] All ISO-NE transmission planning process information in this section is primarily derived from the following sources:
ISO-NE TPPG (2015). ISO-NE Transmission Planning Process Guide. Accessed at: http://www.iso-ne.com/static-assets/documents/2015/07/transmission_planning_process_guide.pdf
ISO-NE TPTG (2015). ISO-NE Transmission Planning Technical Guide. Accessed at: http://www.iso-ne.com/static-assets/documents/2014/12/planning_technical_guide_2014-12-2_clean.pdf
ISO-NE RSP (2015). ISO-NE Regional System Plan. Accessed at: http://www.iso-ne.com/system-planning/system-plans-studies/rsp

on the reliability planning process used to identify transmission solutions required to address reliability needs. These studies are described in Section 4 of Attachment K of ISO-NE's Open Access Transmission (OATT or Tariff).

Reliability Study Models

Base Case Development

The starting point for developing a base case for transmission studies is ISO-NE's Model on Demand (MOD) database. The MOD is a sequential database used for storing modeling data used by ISO-NE to build power flow models. The software stores load data, generation data, topology, and ratings submitted by member companies.[3] The source of assumptions for ISO-NE's system is the Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report) for supply resource and demand assumptions, and the Regional System Plan (RSP) for transmission topology assumptions. The model of the external system, including transmission topology and generation information is sourced from a recent Multi-regional Modeling Working Group (MMWG) base case.[4] For the transmission needs and solutions assessments, the transmission topology in New England includes facilities that are in-service, under construction, planned, and proposed projects.[5] The transmission topology for regions outside of New England is based on the latest MMWG base case.

The Base Cases are stressed by removing the two most impactful generators (i.e. those whose outages create the greatest stress on the transmission system under study) in the study area. These resources could be individual generators or interdependent generating facilities such as combined cycle units. When analyzing a study area ISO-NE might create multiple base cases with different combinations of generator outages. The most impactful generators are considered out-of-service in the Base Case before implementing any contingency analysis. Additional generators could be considered out-of-service when examining alternative load levels. In any given planning cycle, multiple Base Cases are evaluated to assess the impact of different combinations of generators being out of service. The rationale for removing these generators is to replicate a stressed system condition before implementing the contingencies.

Interface Loading

ISO-NE evaluates interface transfer levels that may affect the area under study to cover a full range of existing capabilities. Interface levels are tested up to their maximum and minimum capability by varying generation resources outside the study area. This approach ensures that interface transfer levels are tested at varying levels while maintaining a disciplined approach to unit unavailability consideration.

[3] The MOD database is used to create ISO-NE's portion of the MMWG base case, but MOD database is updated periodically to include updated ratings and newly approved transmission projects. The software is developed by Siemens PTI.

[4] The Multiregional Modeling Working Group (MMWG) is responsible for developing a library of solved power flow models and associated dynamics simulation models of the Eastern Interconnection. The models are for use by the Regions and their member systems in planning future performance and evaluating current operating conditions of the interconnected bulk electric systems.
(See: https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Pages/default.aspx)

[5] The criteria for a merchant transmission facility is for the line to be in-service, under construction, or have an approved PPA; and deliver an import with a capacity supply obligation or a binding contract; and have a certain in service date.

Interfaces internal to the study area, and those in surrounding areas that may affect the study (referred to as coincident interfaces) are considered individually as well as in combination. Each base case is tested at different interface levels. For example, internal and coincident interfaces may be tested individually and in combination at low, medium and high loading levels.

Load Modeling

The load data included in the power flow case is provided by ISO-NE. The CELT Report is the primary source of assumptions used in reliability and transmission planning studies. For the ISO's planning studies, adjustments are made to the CELT report peak load estimates to account for generating station service load and manufacturing load. These load add approximately 1,500 MW to the region (as per the latest transmission planning technical guide). The New England system experiences its peak load in summer. The projected 90/10 summer peak load forecast for the New England Control Area is used for planning studies. The 90/10 Peak Load represents a load level that has a 10% probability of being exceeded due to variations in weather. The load forecast also includes losses of about 8% of the total load, 2.5% for transmission and large transformer losses and 5.5% for distribution losses. The steady state and stability analysis involves testing the system at the following system load levels — peak load, intermediate load, light load and minimum load, where these are:

- 90/10 Summer Peak,
- Intermediate Load (approximate value actual system loads were at or below 90% of the time),
- Light Load (approximate value actual system loads were at or below for 2,000 hours), and
- Minimum Load (derived from actual minimum system loads, and based on a CELT load of 8,500 MW and an additional 364 MW of manufacturing load.

Demand response is modeled as negative load in the base case. Demand resources, excluding energy efficiency, are based on the most recently concluded Forward Capacity Auction (FCA). In addition to the demand resources procured through the FCM, ISO-NE forecasts Energy Efficiency as part of the annual CELT forecast. This Energy Efficiency is forecasted beyond the FCM horizon, and is included separately for studies that analyze time periods beyond the FCM horizon.

Demand Resources are not modeled explicitly in the fixed load level cases representing shoulder, light and minimum loads, because the impact of such resources is included in the actual measured load used to establish the fixed load levels.

Generation Modeling

Generating facilities that are 5 MW and greater are listed in the CELT Report and are explicitly modeled in the planning study base cases. Generation resources that are under construction or have an approved Proposed Plan Application (PPA) are included in the Base Case. Generators that have capacity supply obligations or binding contracts (state-sponsored RFP or financially binding contract) are also included in the Base Case for Transmission Needs Assessments and Transmission Solutions Studies.

For its generation retirement assumptions ISO-NE considers generators that have submitted a Non-Price Retirement Request. Other generators considered unavailable are generators that have an accepted or a rejected Permanent De-list bid, generators that have delisted in the last two rounds of capacity auctions and units that are unavailable because of special circumstances such as denial of license extensions or being physically unable to operate.

Solar Generation Modeling

ISO-NE includes a solar photovoltaic (PV) forecast in its annual CELT Report.[6] The forecast includes solar PV generation that has been installed as of the prior year and a forecast of the PV capacity that is expected to be in-service by the end of each forecast year for the next 10 years. Projections of solar generation capacity that have not already been included in the load forecast are modeled explicitly in the base case.

The PV forecast of solar PV are divided into four mutually exclusive groups:

1. PV as a capacity resource in the FCM
2. Non-FCM Settlement only Resources (SOR) and Generators
3. Behind-the-Meter (BTM) PV Embedded in Load
4. Behind-the-Meter (BTM) PV Not Embedded in Load

Of the four groups, the Behind-the-Meter PV Embedded in Load is already embedded in the CELT forecast and hence is not modeled explicitly in ISO-NE's studies. The other three groups are modeled explicitly as generation or negative loads in the transmission planning studies. Generators that are greater than 5 MW are modeled as individual generators in the study cases. Generators less than 5 MW are modeled as negative loads.

Power Flow Analysis

The contingencies that are tested on the ISO-NE system are derived from the applicable standards and criteria specified by NERC, NPCC and ISO-NE. These standards and criteria form the deterministic planning criteria. These standards and criteria identify the select contingencies that must be tested, and the power flow in each element of the system must remain within its emergency limits following any specified contingency. For most system elements in the ISO-NE region, the Long Time Emergency Ratings are used as the emergency thermal limit. Broadly, the contingencies are of the following types:

- N-1 contingency. This includes the loss of a generator, transmission element, reactive device, different phases of two adjacent transmission circuits on a multiple circuit tower, any two circuits on a multiple circuit tower, a breaker failure, and both poles of a direct current bipolar facility, due to several faults.
- N-1-1 contingency. The first initiating event includes the loss of a generator, loss of a series or shunt compensating device, loss of a transmission circuit and loss of a transformer. After the first event generator dispatch and power flows are adjusted in preparation for the next event. The second event must include all those tested under the N-1 contingency.
- Extreme contingencies. Extreme events are tested because the transmission system can be subjected to events that are more severe than those tested under N-1 and N-1-1 contingency conditions. ISO-NE does not build out the system as a result of the extreme contingencies. Rather, the aim of these studies is to assess the impact of the extreme contingencies on the bulk power

[6] ISO-NE Transmission Planning Technical Guide, November 5, 2015.

system. Based on the results, plans or operating procedures can be developed to reduce the probability of occurrence or mitigate the impact.

Transmission Reliability Studies

Under its regional system planning process, ISO-NE performs assessments of the needs of the transmission system in studies referred to as Needs Assessment.[7] ISO-NE incorporates market responses that have met specific criteria into the Needs Assessment studies. The market responses include resources such as demand-side projects and distributed generation, and Electric Transmission Upgrades (ETU).[8] Resources are incorporated into the needs study if they have cleared a Forward Capacity Auction (FCA), have been selected in, and are contractually bound by, a state-sponsored Request for Proposals (RFP), or have a financially binding contract. ETUs are incorporated into the study if they have Proposed Plan Application (PPA) approval[9], a commercial operation date has been ascertained, and the project meets ISO-NE's threshold and evaluation criteria specified in Section III.12 of the Tariff.

The Needs Assessment examines various aspects of the performance and capability of the New England transmission system. It analyzes the transmission system to determine if it meets applicable reliability standards; has adequate transfer capability to support local, regional, and inter-regional reliability; supports the efficient operation of the wholesale electric markets; or is sufficient to integrate new resources and loads on an aggregate or regional basis. The Needs Assessment also identifies the location and nature of any potential problems on the system, situations that significantly affect the reliable and efficient operation of the transmission system and the time within which market responses or regulated transmission solutions must be developed to address any identified needs. In addition, the Needs Assessments will identify high-level functional requirements and characteristics for regulated transmission solutions and market responses that can meet the identified needs.

If the market responses incorporated into the Needs Assessments do not eliminate or address the needs identified in the study, ISO-NE will develop or evaluate regulated transmission solutions proposed in response to the need. The solutions are identified through a Solution Study or a competitive process depending on the timing and type of solution required. If the solution would be required in three years or less, and is likely to be a Reliability Transmission Upgrade, ISO-NE will evaluate the adequacy of the proposed solution by performing Solution Studies.[10] ISO-NE will also perform Solutions Studies if the first phase of the competitive process yields only one proposed solution.

In coordination with the proponents of regulated transmission solutions and other interested or affected stakeholders, ISO-NE will conduct the studies to identify regulated transmission projects that could address the needs identified in Needs Assessments, and to evaluate whether proposed regulated

[7] ISO-NE's process for the assessment of needs of the transmission system and evaluation of solutions is described in Attachment K, Section 4 of its OATT. ISO-NE has recently updated its Attachment K in compliance with FERC Order 1000, and it is in the process of updating its Transmission Planning Technical Guide.

[8] An Elective Transmission Upgrade is a transmission line or upgrade that is voluntarily funded by projected parties.

[9] Approval under Section I.3.9 of the Tariff.

[10] A Reliability Transmission Upgrade is an upgrade to the transmission system necessitated by system reliability considerations.

transmission solutions meet the needs. The ISO may form and lead targeted study groups to conduct Solutions Studies. Through these studies ISO-NE could identify the solutions that offer the best combination of electrical performance, cost, future system expandability, and feasibility to meet a need identified in a Needs Assessment in the required time frame. The solutions may differ from those proposed by a transmission owner.

If the solution would be required in more than three years, or if it is likely to be a Market Efficiency Transmission Upgrade, ISO-NE will conduct a two-stage competitive solicitation process. ISO-NE will issue a public notice indicating that Qualified Transmission Project Sponsors may submit Phase One Proposals offering solutions that comprehensively address the identified needs. A PTO will also submit a Phase One Proposal as a Backstop Transmission Solution for any need that would be solved by a project located within or connected to its existing electric system. PTOs may submit a joint proposal for a need that would be solved by a project located within or connected to their existing systems.

Projects submitted in Phase One are evaluated by ISO-NE. Based on the results of the evaluation and stakeholder input, projects are selected for a second phase of analysis. After evaluation of Phase Two projects and following receipt of stakeholder input, the ISO will identify the preferred Phase Two Solution. The selected project will be the one that offers the best combination of electrical performance, cost, future system expandability and feasibility to meet the need in the required timeframe.

Chapter 3: California Independent System Operator

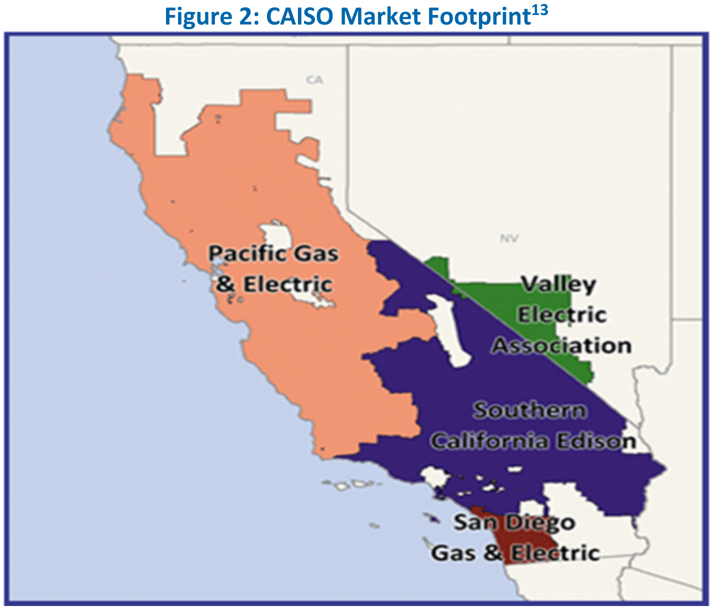
Overview

Of the seven ISO/RTO-type institutions in the U.S, the California Independent System Operator (CAISO) is the only one in the U.S. portion of the Western Interconnection. CAISO began commercial operation on March 31, 1998. It is a nonprofit public benefit corporation governed by a five member Board of Governors.[11] The Board members are elected to three-year staggered terms and are appointed by the Governor of California subject to confirmation by the state senate. Like most ISO/RTOs, CAISO performs a wide range of functions such as scheduling and dispatching wholesale generation, determining the locational marginal prices for energy, administering the energy and ancillary markets, scheduling transmission within the regional grid, coordinating the planning process for new transmission investment, monitoring the markets for non-competitive tendencies, and implementing mitigation measures. CAISO manages the flow of electricity across nearly 80% of the wholesale power lines that comprise the power grid in California and parts of Nevada.[12] CAISO is the largest of the 38 balancing authorities (BAs) in the Western Interconnection, with nearly 35% of the total electric load.

Operating Footprint

In addition to facilitating a competitive wholesale power market and serving as the transmission grid operator for the balancing authority (BA) footprint, CAISO is responsible for identifying and planning the development of additions and upgrades to the transmission infrastructure that makes up the CAISO BA footprint. The CAISO BA footprint, and hence planning footprint, is reflected in Figure 2.

Figure 2: CAISO Market Footprint[13]



Source: FERC

[11] CAISO, "ISO/RTO Governance Structure."
[12] CAISO- Accessed at: http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/The-ISO-grid.aspx
[13] FERC - http://www.ferc.gov/market-oversight/mkt-electric/california.asp

Some of the non-CAISO BAs in the state include: PacifiCorp, Los Angeles Department of Water and Power (LADWP), Sierra Pacific Power (SPP), Imperial Irrigation District (IID) and Balancing Authority of Northern California (BANC). CAISO manages the grid operations of multiple transmission owners, including three investor-owned utilities: Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric Company (SDG&E). Collectively, CAISO delivers nearly 260 million megawatts-hours of electricity a year to around 30 million customers in its service area using 26,000 circuit miles of transmission.

Recent Initiatives to Improve the Transmission Planning Process

When CAISO began commercial operation in 1998, it relied almost exclusively on its Participating Transmission Owners (PTOs) to develop transmission expansion plans, and then performed a very high level assessment of the integrated PTO expansion plans to ensure the reliable and economic operation of the transmission system. CAISO discontinued this approach in 2006 when it took initial steps toward its goal of creating an annual CAISO Consolidated Transmission Plan.[14] The first transmission plan for the CAISO controlled grid was completed in January of 2007, and it provided a single source of information relating all planning activities undertaken by the CAISO, PTOs, and stakeholders.

With the issuance of Order 890, CAISO took yet another step forward to refine, clarify, and document its integrated transmission planning process. It published the first version of the Business Practice Manual (BPM) for the Transmission Planning Process in December of 2007, and implemented its first Order 890-compliant process in 2008.

The State of California's adoption of new environmental policies and goals[15] created the need for additional changes to the CAISO planning process which were incorporated into tariff revisions that became effective in December of 2010. Changes to the planning process as a result of these tariff revisions included the introduction of a policy-driven criterion for new transmission and a conceptual statewide transmission plan to better inform transmission planning decisions.[16] In addition, the CAISO introduced a competitive solicitation process to determine the most qualified project sponsor, considering both independent transmission developers and PTOs, to construct, own, finance, operate, and maintain certain regional transmission facilities. CAISO termed this new planning process the "revised transmission planning process" or RTPP, and published the first conceptual statewide plan in February of 2011 to be used to inform the 2010/2011 transmission planning cycle.

Most recently, CAISO completed a series of additional revisions to its transmission planning process to comply with the regional planning requirements set forth by Order 1000. On December 18, 2014, FERC

[14] CAISO, Memorandum Re: 2005 ISO Transmission Plan, March 2, 2006.
[15] These policies and goals included the adoption on May 4, 2010 of a statewide policy on the use of coastal and estuarine water for power plant cooling by the State Water Resources Control Board, and the state's move toward a renewable portfolio standard of 33% by 2020.
[16] CAISO, "2012-2013 Transmission Plan," March 20, 2013.

fully accepted the CAISO's third round of tariff revisions, making CAISO the first region in all interconnections to fully comply with the regional requirements of Order No. 1000.

Transmission Planning Process

CAISO is a registered NERC planning authority and is therefore responsible for ensuring that the CAISO-controlled grid is in compliance with NERC standards. Specifically, the NERC TPL-001 through TPL-004 reliability standards are the primary drivers for determining reliability upgrade needs of the CAISO-controlled grid.

In addition to the NERC standards, CAISO evaluates system performance to meet Western Electricity Coordination Council (WECC) transmission planning system performance criteria[17] and CAISO Planning Standards.[18] The CAISO Planning Standards cover the following:

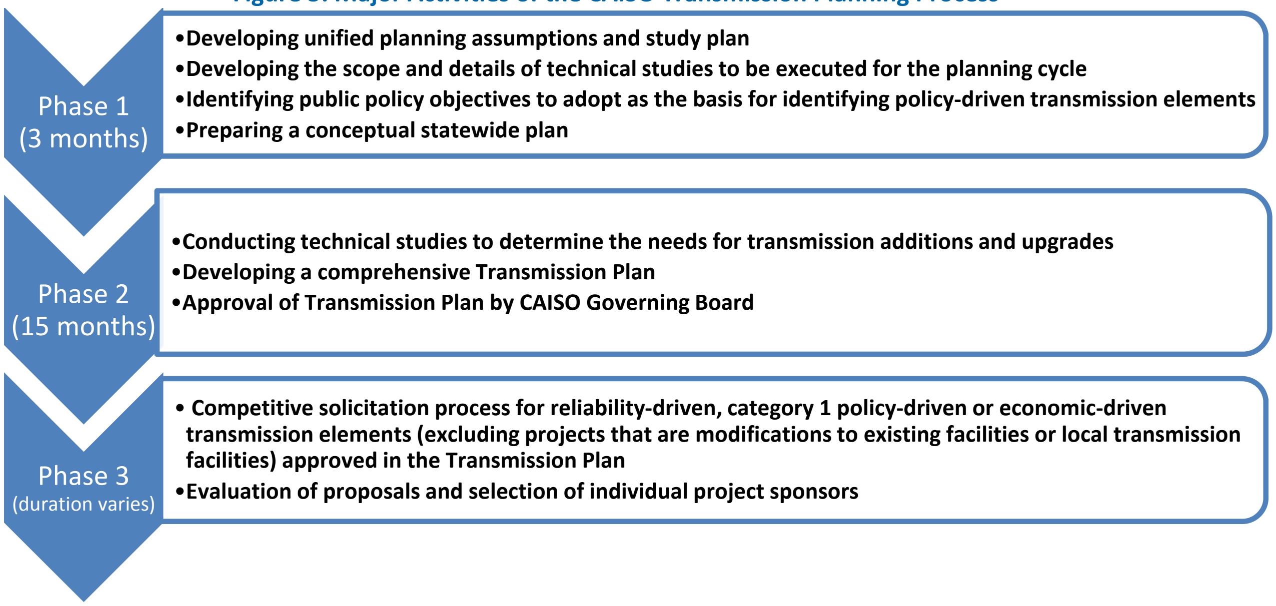
- address specifics not covered in the NERC reliability standards and WECC regional criteria;
- provide interpretations of the NERC reliability standards and WECC regional criteria specific to the ISO-controlled grid; and
- identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

Transmission Planning Studies

CAISO's comprehensive Transmission Planning Process (TPP) is initiated on an annual basis and consists of three consecutive phases spread over a roughly 23 month period. The TPP commences each January, and results in the Board-approval of necessary projects 15 months later. Major deliverables of the TPP are the conceptual statewide plan and unified planning assumptions and study plan (for Phase 1); technical studies and comprehensive transmission plan (for Phase 2); and, if applicable, selection of proposals to build and own new transmission facilities identified in the Board-approved plan (for Phase 3). The three planning phases are summarized in Figure 3.

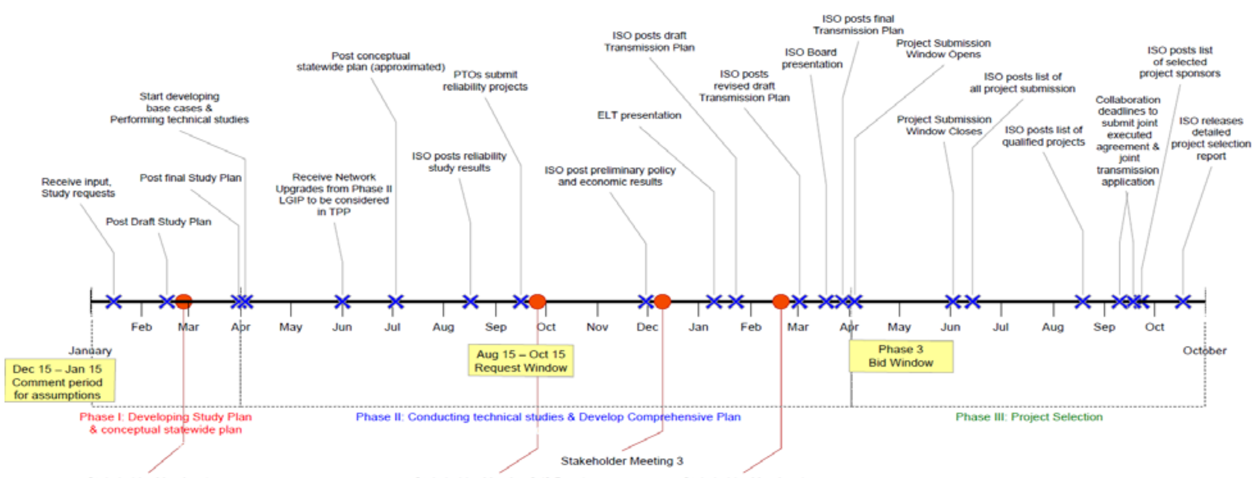
[17] https://www.wecc.biz/Pages/Compliance-UnitedStates.aspx
[18] http://www.caiso.com/Documents/FinalISOPlanningStandards-April12015_v2.pdf

Figure 3: Major Activities of the CAISO Transmission Planning Process[19]



Phases 1 and 2 of the transmission planning process are conducted over a 15-month period. As such, the last three months of phase 2 of one planning cycle will overlap with phase 1 of the next cycle, which also spans three months. The CAISO will conduct Phase 3 of the TPP, the competitive solicitation for sponsors to build and own eligible transmission facilities identified in the final plan, following Board approval of the comprehensive plan and in parallel with the start of phase 2 of the next annual cycle. The general timeline of the TPP is graphically represented in Figure 4.

Figure 4: General Timeline of CAISO Transmission Planning Process



Source: *CAISO BPM*

[19] CAISO, "Business Practice Manual for the Transmission Planning Process," Version 13, March 3, 2014.

Transmission Reliability Studies

The first step of the CAISO TPP technical studies is a comprehensive reliability assessment to identify the need for transmission upgrades and additions to ensure that the CAISO controlled grid will meet or exceed all applicable NERC Standards and WECC/CAISO reliability criteria in both the near-term (1- or 2-year, 5-year) and longer-term (10-year) study horizons. The term "reliability assessments" encompasses several technical studies conducted by CAISO such as power flow, transient stability, and voltage stability studies. These assessments evaluate transmission facilities across voltages of 60 kV to 500 kV, and are performed on the bulk system as well as the local areas under the CAISO controlled grid.[20]

Several different hours are selected for study to cover critical system conditions driven by generation levels, demand levels, and import, export, or other path flows. The GE-PSLF™ modeling tool is the primary study tool used for evaluating system performance under normal and outage conditions. Additional modeling tools are used for more detailed reliability studies involving voltage stability, small signal stability analyses, and transient stability.

If during the course of conducting the reliability assessments system performance criteria are not met, CAISO will develop mitigation plans to address the performance issues and will consider alternative mitigation proposals submitted by PTOs and other stakeholders during the CAISO Request Window and in accordance with the CAISO's submission requirements.[21] Mitigation plans may include upgrades to the transmission infrastructure, implementation of new operating procedures and installation of automatic special protection schemes. All reliability analysis, results and mitigation plans are documented in the CAISO Comprehensive Transmission Plan.

Other Transmission Studies

During Phase 2 of the TPP, CAISO conducts a series of sequential technical studies and analyses to identify transmission upgrades or additions, or non-transmission alternatives, needed to reliably operate the CAISO controlled grid, meet the state's public policy requirements, and provide additional benefits to ratepayers.

In addition to the reliability assessments described above, CAISO performs additional technical studies related to long-term Congestion Revenue Rights (LT-CRRs) and local capacity requirements. CAISO will evaluate Generator Interconnection Process (GIP) network upgrades that might be eligible for modification or addition in the comprehensive Transmission Plan, as well as any Location Constrained Resource Interconnection Facilities (LCRIF) or merchant projects submitted through the CAISO Request Window before proceeding with the evaluation of policy-driven needs (below).

[20] Reliability assessments can also be performed by PTOs for their service territories as part of their roles as NERC designated Transmission Planners. These studies are performed in accordance with CAISO's planning methodologies, unless otherwise noted, and are documented in the TPP Study Plan.

[21] CAISO will open a request window during Phase 2 of the TPP following the posting of the technical reliability study results for the submission of proposed transmission or non-transmission solutions to meet the identified reliability-driven needs. PTOs and any other interested party can submit proposed solutions, but they must do so using the submission form that is available on the CAISO website.

Public Policy

The focus of CAISO's policy-driven needs assessment for the past number of years has been on identifying new transmission projects needed to achieve California's Renewable Portfolio Standard that calls for eligible renewable resources to provide 33 percent of the state's electric retail sales in 2020 and beyond. Because the base renewable resource portfolio is included in the models used for the reliability assessments, the results of the reliability assessments are considered to be part of the policy-driven need assessment. Still, those study results are supplemented with additional studies that contribute to identifying the "least regrets" policy-driven transmission needs considering both the base case and alternative renewable resource portfolios. Additional studies performed to identify the "least regrets" policy-driven transmission needs include production cost modeling simulations to identify stressed system conditions for evaluation using power flow and stability tools to ensure all system performance requirements continue to be met; and a deliverability assessment to verify the deliverability (within CAISO or import into CAISO) of the resources modeled in the renewable resource portfolios such that the RPS targets will indeed be met.

Economic Studies

Once CAISO has identified policy-driven transmission solutions in addition to the previously identified reliability-driven solutions, these results are taken as inputs and modeled in economic planning studies. This approach ensures that the economic-driven transmission needs are not redundant and are above and beyond reliability- and policy-driven transmission needs. The purpose of the economic studies is to identify potential congestion within the CAISO-controlled grid and potential additional network upgrades that will provide economic benefit for CAISO ratepayers.

Reliability Study Models

Base Case Development

A combination of peak, off-peak, and light load seasonal base cases are created for the assessment of reliability-driven transmission needs. CAISO performs reliability assessments on the bulk system (north and south) as well as the local areas under the ISO controlled grid. Participating Transmission Owner's (PTO) develop base cases for local areas within their system. Local areas are studied separately, then in combination at the transmission owner and bulk system level. PTOs use power flow base cases from WECC as the starting point for their base cases, and CAISO has final approval of base cases.

Multiple base cases may be created for each study area, with variations in load and generation dispatch conditions, depending on factors that might stress the area. For example, an area may have base cases representing summer peak, winter peak and spring off-peak load conditions. A 90/10 load level is used for local area base cases, an 80/20 load level for the PTO system cases, and 50/50 for the California bulk system study. Dispatch in each base case is adjusted to stress the study area's interfaces to their rated limits. As a result over a hundred base cases might be developed in order to perform the reliability assessment for a PTO's system, and CAISO may utilize hundreds of base cases for its system-wide transmission planning study.

In addition to the base cases, several sensitivity cases are studied for many of the local areas. These cases vary from planning cycle to planning cycle and are used to assess impacts of specific assumptions on the reliability of the transmission system under high or low CEC forecasted load, heavy renewable output, generation retirement scenarios, and high or low hydro conditions. The Base Cases used in the 2015-16 TPP are listed in Table 2. The sensitivity cases are shown in Table 3.

Interface Loading

Generation dispatch in each base case is adjusted to stress the interfaces relevant to the study area. Interfaces are stressed to their rated limits. Flows on major CAISO internal paths and paths that cross BA boundaries may vary depending on the study area and system conditions.[22] For local area studies, transfers on import and monitored internal paths are modeled as required to serve load in conjunction with internal generation resources. For bulk system studies, CAISO stresses its major import and internal transfer paths.

[22] In the context of this report, a path is a Western Electricity Coordinating Council (WECC) defined interface within an area or between areas in the bulk power system. A path could comprise a single or multiple transmission elements. The origination point or substation for facilities in a path could be common or different, and the termination point could also be common or different.

Table 2: Base Case Studies in the 2015-2016 CAISO Reliability Assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2017	2020	2025
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak Summer Partial Peak
Humboldt	Summer Peak Winter	Summer Peak Winter Peak Spring Light	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter	Summer Peak Winter Peak Spring Light	Summer Peak Winter peak
North Valley	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula)	Summer Peak Winter peak - (SF & Peninsula) Spring	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Kern	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Central Coast & Los Padres	Summer Peak Winter	Summer Peak Winter Peak Spring Light	Summer Peak Winter Peak
Southern California Bulk transmission system	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak Summer Partial Peak
SCE Metro Area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
SCE Northern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
SCE Eastern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
San Diego Gas and Electric (SDG&E) area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak Winter Peak
Valley Electric Association	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak

Note: - Peak load conditions are the peak load in the area of study.
- Off-peak load conditions are approximately 50-65 per cent of peak loading conditions, such as weekend.
- Light load conditions are the system minimum load condition.
- Partial peak load condition represents a critical system condition in the region based upon loading, dispatch and facilities rating conditions.

Source: 2015-2016 Final Study Plan

Table 3: Sensitivity Studies in the 2015-2016 CAISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long Term Planning Horizons
	2017	**2020**	**2025**
Summer Peak with high CEC forecasted load			PGE&E Local Areas SCE Metro SCE Northern, SDG&E Area
Summer Peak with heavy renewable output and minimum gas generation commitment		PG&E Bulk PG&E Local Areas SCE Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SDG&E Area	
Summer Off-peak with heavy renewable output and minimum gas generation commitment (renewable generation addition)			
Summer Peak with OTC plants replaced			
Summer Peak with low hydro output			
Retirement of QF Generation			PG&E Local Areas
Summer Peak and Summer Off-peak with heavy renewable output and IID southern ties to ISO normally open			SDG&E Area

Source: 2015-2016 Final Study Plan

Load Modeling

CAISO studies reflect future demand forecasts published in the California Energy Demand Forecasts released by the California Energy Commission (CEC), and account for reduced energy demand from energy efficiency. The forecast used for the TPP technical studies reflect a 1-in-10 load forecast for the local area studies, and 1-in-5 coincident peak load forecasts for the CAISO system-wide studies. Where bus-level load information is required, CAISO augments the CEC forecasts with those developed by the PTOs, and documents the methodology utilized by the PTOs for developing these forecasts in the annual TPP study plan.

Generation Modeling

New generators modeled in CAISO's reliability studies are classified as follows:[23]

- Level 1: Under construction
- Level 2: Regulatory approval received
- Level 3: Application under review
- Level 4: Starting application process
- Level 5: Press release only

[23] CAISO, "2015-2016 Transmission Planning Process Unified Planning Assumptions and Study Plan – Draft," February 17, 2015.

For the 2-5-year planning base cases, generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study will be modeled in the initial power flow cases. Conventional generation in the pre-construction phase with executed Large Generator Interconnection Agreements and progressing forward are modeled as off-line, but are available as a non-transmission solution to identified needs. Renewable generation with all permitting and necessary transmission approved and expected to be in-service within 5 years may also be modeled based on input provided by the California Public Utilities Commission (CPUC) and the status of CAISO interconnection agreements.

For the 6-10-year planning base cases, only generation that is under construction or has received regulatory approval (Levels 1 and 2) will be modeled in the initial power flow cases. If additional generation is required to achieve an acceptable initial power flow case, then generation from Levels 3, 4, and 5 may be used.

The CPUC and California Energy Commission (CEC) provide CAISO with the RPS generation portfolios that are to be included in the initial power flow cases. To the extent that out-of-state renewable resources are contained within these generation portfolios, they are reflected in the CAISO models. Generation retirements and any assumed replacement generation reflected in the studies consider input provided to CAISO by the CPUC and CEC as well.

Power Flow Analysis

In addition to system normal conditions, a number of contingencies are evaluated as part of the reliability assessment. Conventional and governor power flow contingency analyses are performed on all backbone and regional planning areas consistent with NERC transmission planning standards TPL-001 through TPL-004, WECC regional criteria and CAISO planning standards. Specifically, single and multiple element contingencies as defined in the annual TPP study plan, are evaluated for all local areas and select areas outside the CAISO controlled grid. The contingencies examined by CAISO include the loss of a single transmission element (N-1), the simultaneous loss of a single generator and a single transmission element (G-1+N-1), and the loss of a transmission element followed by the loss of a second transmission element (N-1-1).[24] Extreme events resulting in the loss of multiple elements are also assessed as required by NERC, however the analysis of extreme events is not included within the transmission plan documentation unless the analysis drives the need for mitigation plans to be developed.

[24] NERC's Transmission Planning (TPL) Standards define the contingencies that planning entities are required to analyze. TPL-001 through TPL-004 initially defined four categories of contingencies – Categories A through D. Category A assumes all facilities are in service. Category B events result in the loss of a single transmission element and Category C in the loss of two or more elements. Category D events are considered extreme events, and they result in the loss of multiple elements. FERC has approved TPL-001-4 to replace the previous version of TPL-001 and also TPL-002, TPL-003 and TPL-004. In TPL-001-4 events are classified as planning events or extreme events. Planning event contingencies are grouped into 8 categories, P0 through P7, which address contingencies similar to Categories A through C. P0 assumes all facilities are service. P1 and P2 are different categories of single element contingencies, and P3 through P7 are different categories of multiple element contingencies TPL-001-4 extreme events are similar to Category D events. TPL-001-4 would replace all other versions of the TPL Standards by December 31st, 2015.

Violations observed as a result of the contingency studies are documented together with potential mitigation solutions and reported in the preliminary reliability assessment study results. Following a request for mitigations from the PTOs and a stakeholder review process, mitigations for all noted violations may take the form of congestion management, new or modified Special Protection Systems or Remedial Action Schemes, other non-transmission alternatives, or capital improvement projects.

Chapter 4: Electric Reliability Council of Texas ERCOT

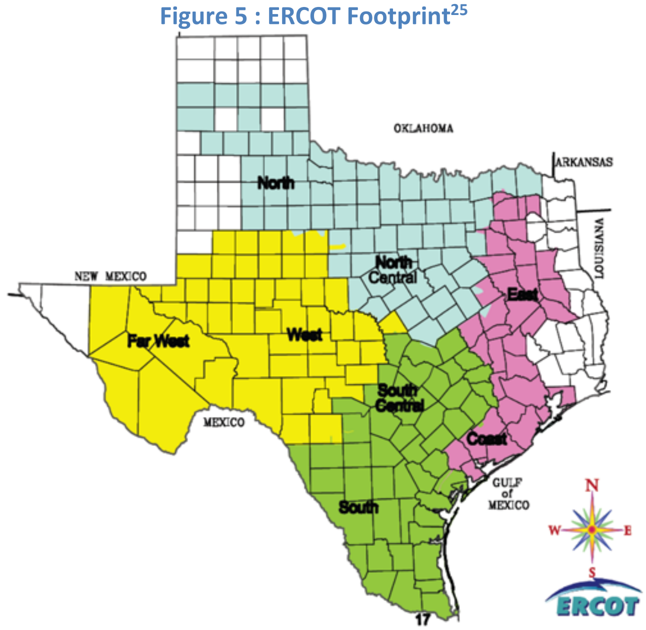
Overview

ERCOT is unique in the United States because its electricity grid is not synchronously connected outside of the state. Because of its separateness, ERCOT is primarily regulated by the Public Utility Commission of Texas (PUC) and the Texas Legislature. The PUC approves the ERCOT system administration fee and has general oversight authority, including the ability to order audits. ERCOT is a membership-based nonprofit corporation, governed by a Board of Directors and subject to oversight by the PUCT and the Texas Legislature. ERCOT's members include consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities (transmission and distribution providers), and municipal-owned electric utilities.

Operating Footprint

As the independent system operator for the region, ERCOT schedules power on an electric grid that connects more than 46,500 miles of transmission lines and 550 generation units. Currently, an estimated $6.2 billion of transmission additions are under development and expected to be placed in commercial operation over the next five years. The ERCOT BA footprint, and hence planning footprint, is reflected in Figure 5. ERCOT also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for 6.7 million premises in competitive choice areas. In 2015, ERCOT served about 90% of Texas load representing more than 24 million consumers and managed more than 7 million electric-service ID's (premises. Approximately 6.8 million advanced meters (representing 97 percent of ERCOT load in competitive areas) are deployed facilitating settlement with 15-minute interval data.

Figure 5 : ERCOT Footprint[25]



[25] http://www.ercot.com/content/news/presentations/2015/2014_Regional_Transmission_Plan_public.zip

ERCOT works with the electric industry organizations in the ERCOT control area to ensure reliable power operations for the wholesale and retail competitive markets. Market participants include entities performing the functions of qualified scheduling entity (QSE), load serving entity (LSE), resource entity (RE) or transmission/distribution service provider (TDSP). TDSPs provide the transmission infrastructure and help ERCOT to manage system reliability. There are more than 150 TDSPs in ERCOT. Of these, some are transmission service providers (TSPs) only. Most of these firms became TSPs as a result of the transmission buildouts during the 2008-2014 period to support the Competitive Renewable Electricity Zone program (CREZ).

Transmission Planning Process

ERCOT has a comprehensive Transmission Planning Process conducted on a recurring basis.[26] The ERCOT process reflects and reinforces the framework and process conducted by the Public Utility Commission of Texas (PUCT) to site and construct new transmission lines in the state. The transmission siting process is somewhat unique and does not involve FERC oversight.

Transmission Planning Studies

The process of planning a reliable and efficient transmission system for the ERCOT Region is composed of several complementary activities and studies. The ERCOT-administered System Planning activities comprise near term studies, including the Regional Transmission Plan (RTP), Regional Planning Group (RPG) submissions and review, and ongoing long-range studies, which are documented in the Long-Term System Assessment (LTSA). In addition to these activities, transmission service providers (TSPs) conduct analysis of local transmission needs outside of the ERCOT Planning Process.

Transmission Reliability Studies

The Long-Term System Assessment (LTSA) process is based upon scenario analysis techniques to assess the potential needs of the ERCOT system up to 15 years into the future. The role of the LTSA is to evaluate the system upgrades that are indicated under each of a wide variety of scenarios in order to identify upgrades that are robust across a range of scenarios or might be more economic than the upgrades that would be determined considering only near-term needs in the RTP development.

Proposed transmission projects are largely categorized for evaluation purposes into reliability-driven projects and economic-driven projects.

The differentiation between these two types of projects is based on whether a simultaneously-feasible, security-constrained generating unit commitment and dispatch is expected to be available for all hours of the planning horizon that can resolve the system reliability issue that the proposed project is intended to resolve. If it is not possible to forecast a dispatch of the generating units such that all reliability criteria are met without the project, and the addition of the project allows the reliability criteria to be met, then the project is classified as a reliability-driven project. If it is possible to simulate a dispatch of the generating units in such a way that all reliability criteria are met without the project, but the project may

[26] All ERCOT information in this section is derived from the following sources, unless specified otherwise:
ERCOT Planning Guide (2014). Accessed at: http://www.ercot.com/mktrules/guides/planning/current
ERCOT(2014). ERCOT Regional System Plan. Accessed at: http://www.ercot.com/news/presentations/

allow the reliability criteria to be met at a lower total cost, then the project is classified as an economic-driven project. When performing a simulation of the generating unit commitment and dispatch, only contingencies and limits that would be considered in the operations horizon will be simulated. For reliability-driven projects, the comparison of project costs generally includes only the relative capital costs of the alternatives.

While the LTSA process considers a broad set of economic and reliability factors, the RTP process is largely focused on reliability factors. The RTP does consider capital cost differences between alternatives but not a broader set of economic benefits. As future study assumptions become more certain, the RTP supports actionable plans to meet real near-term economic and reliability-driven system needs. In support of stakeholder-identified or ERCOT-assessed projects, the RPG review process leads to endorsement of individual projects that maintain reliability or increase system economy.

Other Transmission Technical Studies

Annual Report on Constraints and Needs in the ERCOT Region

This report provides an assessment of the need for increased transmission and generation capacity for the next six years (2015 through 2020) and provides a summary of the ERCOT Regional Transmission Plan to meet those needs.

RPG Planning Reviews

Except for minor transmission projects that have only localized impacts and projects that are directly associated with the interconnection of new Generation Resources, all transmission projects in the ERCOT Region undergo a formal review by the RPG. In addition, ERCOT performs an independent analysis of the need for major transmission projects that are submitted for RPG Project Review.

Economic Studies

Once ERCOT has identified stakeholder suggested transmission solutions in addition to the previously identified reliability-driven solutions, these results are taken as inputs and modeled in economic planning studies.

The purpose of the economic studies is to identify potential congestion and/or constraints within the ERCOT-controlled grid and potential additional network upgrades that will provide economic benefit for consumers. The studies are performed using production cost simulation tools. In the first step of the economic studies, a production cost simulation is run. Congestion is identified and ranked in severity of congestion costs and congestion duration in hours. In the second study step, plans to mitigate identified congestion are evaluated for each high priority economic study. Economic benefits of each network upgrade alternative are quantified. At the conclusion of the process, ERCOT presents the comprehensive Transmission Plans (LTSA and RTP) to its Board for approval, which identifies solutions needed to reliably operate the ERCOT controlled grid, meet the state’s requirements, and provide additional benefits to consumers.

Reliability Study Models

Base Case Modeling

In 2014, ERCOT initiated use of revised scenarios for the LTSA developed under the RPG stakeholder process. These are summarized in Table 4.

Table 4 : 2014 LTSA Scenarios Developed by Stakeholders

Candidate Scenarios	Description
Current Trends	Trajectory of what we know today (e.g., LNG export terminals and West Texas growth, prolonged high oil prices)
Global Recession	Significant reduction in economic activities in the U.S. and abroad
High Economic Growth	Significant population and economic growth from all sectors of the economy (affecting residential, commercial, and industrial load)
High Efficiency/High DG/Changing Load Shape	Reduced net demand growth due to increase in distributed solar, cogeneration and higher building and efficiency standards
High Natural Gas Prices	High domestic gas prices
Stringent Environmental Regulation/Solar Mandate	On top of current regulations, the Environmental Protection Agency (EPA) also regulates GHG emissions. Federal or higher Texas renewable standards. More stringent water regulations. Texas legislative mandate on utility-scale and distributed solar development.
High LNG Exports	Significant additional construction of liquefied natural gas (LNG) terminals (beyond Current Trends)
High System Resiliency	Severe climate and system events leading to more stringent reliability and system planning standards
Water Stress	Low water availability
Low Global Oil Prices	Sustained low oil prices

For its near term transmission planning process, the ERCOT Steady State Working Group (SSWG) develops a set of base cases to assess the ability of the transmission system to reliably serve customer load under a variety of possible future conditions. The cases include sixteen steady planning models, three transient stability cases, and a short circuit case. The SSWG models provide base cases that planners can use to develop study-specific planning cases. For its annual Reliability Transmission Plan analysis, ERCOT develops two sets of models based on the SSWG cases – the RTP Reliability Models for reliability needs assessment and the RTP Economic Models for production cost economic analysis.

ERCOT's assumptions typically result in base cases with total load that exceeds the projected generation dispatch. To solve its base cases developers of the cases might adjust generation dispatch and scale load outside the study area. The adjustments to generation dispatch include dispatching mothballed resources and increasing the dispatch of variable generation resources. For specific planning studies planners may adjust the SSWG model to eliminate the impact of the methods need to initially solve the case. Changes implemented for the RTP cases include conservative dispatch of wind resources in the study area, and elimination of mothballed generation in the study area. Load outside the study area may also be reduced to balance load and generation.

Interface Loading

ERCOT models interfaces into constrained study areas at their limit. ERCOT stresses the power flow study cases by using a combination of generation dispatch adjustments and load scaling outside the study area to adjust interface loadings to their limits.

Load Modeling

The RTP typically utilizes two demand forecast sources for the reliability portion of the study. The first is the bus load forecast derived from the Annual Load Data Request (ALDR) and implemented in the SSWG Data Set B (future year) base cases by the TSPs. This load forecast includes the load represented by the TSPs and self-served load of customers and is found in the SSWG summer peak start cases.

The other demand forecast source is the ERCOT-developed 90th percentile weather zone load forecast. Both forecasts assume that summer peak is deemed to be the critical system condition of interest in ERCOT due to the high air conditioner load that exists during summer afternoons in Texas.

Of these forecasts, the RTP process typically uses the higher of the two sources in its analysis. Using the highest non-coincident load forecast for each weather zone results in a simultaneous system demand greater than the amount of generation available to serve the load plus reserves for all of the base cases. ERCOT does not expect that all zones will reach their non-coincident peaks at the same time so this system-wide load value is likely higher than what would be expected to occur in real-time operations.

For the LTSA, separate load forecasts are considered for different scenarios; however, due to the design of the process, some scenarios utilize the same load forecast as other scenarios. Table 5 outlines the mapping and use of the forecast in the 2014 LTSA process.

Table 5 : 2014 LTSA Scenarios Developed by Stakeholders, Load Forecast Mapping, and How Utilized

Forecasted Scenarios	Scenarios that Used Same Forecast	Used In Transmission Analysis
Current Trends	Current Trends, High System Resiliency	Yes
High Economic Growth	High Economic Growth, High LNG Exports	Yes
Stringent Environmental	Stringent Environmental	Yes
Global Recession	Global Recession, Low Global Oil Prices, Water Stress	Yes
High Energy Efficiency And Distributed Generation	High Energy Efficiency And Distributed Generation	No
High Natural Gas	High Natural Gas	No

Generation Modeling

Generation in the RTP cases is modeled in accordance with the RTP process document. The initial generation dispatch information of all existing conventional generation (natural gas, coal and nuclear) is retained from the SSWG start cases initially but may be re-dispatched to relieve transmission overloads. Wind, solar and hydro units are dispatched according to the guidelines specified in the RTP process document. Future generation units are added to the start cases and dispatched according to their resource type. For the RTP, mothballed generation units inside a study region are not placed in-service when that region is analyzed in accordance with SSWG and RPG guidelines. The available capacity of switchable units is left unchanged from SSWG cases unless notice is received from the resource owner to change the available capacity for one or more study years.

Power Flow Analysis

For the LTSA, ERCOT conducts reliability analysis on each of the scenario-appropriate base cases. In 2014, these were created for 2024 and 2029 to determine the potential transmission needs of the system. Reliability-driven projects and economic alternatives or supplements were documented separately for consideration in subsequent shorter-term study horizons. Near-term planning studies (e.g. the RTP) reference long-term reliability constraints when proposing projects in the same geographical area.

As an initial review, a DC Security-Constrained Optimal Power Flow (SCOPF) run was utilized to identify any unresolvable constraints under relevant contingencies. All NERC Category B and some NERC Category C contingencies were studied. The NERC C contingencies that were included in the study are:

- the loss of double circuit lines that share towers for more than 0.5 miles,
- the loss of a generation resource followed by another contingency, and
- the loss of a 345/138-kV transformer followed by another contingency.

In addition to the N-1 and G-1+N-1 analysis[27], ERCOT performs analysis of X-1+N-1 post contingency conditions. Planned improvements identified in the RTP typically include 69-kV, 138-kV and 345-kV line upgrades, and 138/69-kV and 345/138-kV autotransformer upgrades.

Contingencies at all voltage levels are evaluated while only monitoring the 345-kV network. First, ERCOT begins with the premise that most of the 138-kV and 69-kV network upgrades would occur through the near-term planning process. Furthermore, because those upgrades would be identified in the near-term planning process, they would be missing from the LTSA start cases and would not need to be addressed in the LTSA reliability analysis. In the rare instance that large clusters of the 138-kV system are overloaded in the study and require a solution at the 345-kV level, they are included in the LTSA. Limiting the system monitoring allows ERCOT to concentrate principally on the 345-kV network and bulk transmission needs of the system. Overloaded 345-kV elements requiring upgrades regardless of system dispatch are addressed and documented as reliability upgrades.

[27] G-1+N-1 contingency refers to loss of a generating unit and a transmission element
X-1+N-1 contingency refers to loss of a transformer and a transmission element

Chapter 4: New York Independent System Operator (NYISO)

Overview

New York Independent System Operator (NYISO) took operational control of New York's power grid from the erstwhile New York Power Pool on December 1, 1999.[28] The primary responsibilities of NYISO include: ensuring reliable operation of New York's bulk electricity grid; administrating competitive wholesale electricity markets; planning for future power systems needs and advancing the technological infrastructure of the power system serving New York.

NYISO is a not-for-profit corporation regulated by the Federal Energy Regulatory Commission. It is governed by a 10-member board which also includes the NYISO President & CEO. There are 8 transmission owners (TOs) associated with the NYISO market. They include: Central Hudson, Con Edison, National Grid, New York State Electric & Gas, Orange and Rockland Utilities, Rochester Gas and Electric, and Long Island Power Authority.

Operating Footprint

NYISO's market footprint covers the whole of New York State. New York's bulk power system includes nearly 11,086 circuit-miles of high voltage transmission lines.[29] The state has installed generation resources of 39,000 MW. Nearly two-thirds of New York's electricity is used in the southeastern part of the state (Lower Hudson Valley, New York City and Long Island), yet only half of the state's generating capacity is located in this region. In 2014, the actual peak demand was 29,782 MW and the total energy consumption was 160,059 GWh. The total in-state renewables capacity, including hydro, is 6,264 MW — on-shore wind accounts for nearly 1,746 MW of this renewables capacity. NYISO administers the market through eleven load zones or balancing areas. The zones are illustrated in Figure 6. Because most of the relatively cheaper and more efficient generation resources are located in the Western and Upstate areas of New York (Zone A through E), power generally flows from the north and west, through Zones G, H and I in the Lower Hudson Valley (LHV) area, into New York City.

[28] See: http://www.nyiso.com/public/about_nyiso/nyisoataglance/history/index.jsp

[29] All NYISO system facts are sourced from: NYISO (2015). *2015 Power Trends.* Accessed on Oct 21, 2015 at: http://www.nyiso.com/public/webdocs/media_room/press_releases/2015/Child_PowerTrends_2015/ptrends2015_FINAL.pdf

Figure 6 Map of NYISO Zones

Source: FERC

Transmission Planning Process

Under NERC's Operating Standards setting forth fundamental bulk power system operating requirements, primary responsibility for reliable operation of the power system is vested with the control area operator. For New York, the control area operator is the NYISO. In addition, Northeast Power Coordinating Council (NPCC) is the NERC designated regional reliability coordinator for the Northeast region. NPCC includes control areas covered by both NYISO and ISO-NE. NPCC has three basic categories of documents: Criteria, Guidelines, and Procedures. The key NPCC document relevant to transmission planning is Directory #1, "Design and Operation of the Bulk Power System", which establishes the principles of interconnection planning and operations. The New York State Reliability Council (NYSRC) Reliability Rules define the performance that constitutes compliance. These rules incorporate the NERC Planning Standards and Operating Policies and the NPCC Criteria, Guidelines and Procedures. The NYSRC Reliability Rules also include New York-specific reliability rules and local transmission owner reliability rules. In addition, NYRSC also establishes the annual statewide Installed Reserve Margin (IRM) requirements and local capacity requirements (LCRs) for zones in New York City (Zone J), Long Island (Zone K) and Lower Hudson Valley (Zone G-J).

NYISO broadly defines reliability in terms of adequacy and security. Adequacy, which includes both generation and transmission adequacy, refers to the ability of the bulk power system to meet aggregate customer requirements at all times, accounting for both scheduled and unscheduled outages of system components. Security is the ability of the bulk power system to withstand unanticipated loss of system elements. System adequacy is usually measured in terms of probability of not having sufficient transmission and generation resource to meet expected demand. This is measured in terms of loss of load expectation (LOLE). NYISO plans the system to meet an LOLE criteria of 0.1 days per year, i.e., a loss of load for one day in ten years. This requirement forms the basis of New York's installed capacity and resource adequacy requirements as well.

Contingencies and their response requirements are outlined in applicable standards, criteria and rules of North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), NY State Reliability Council (NYSRC) and NYISO transmission planning manual.

Transmission Planning Studies

Transmission Reliability Studies

NYISO's basic transmission planning process is the Comprehensive System Planning Process (CSPP).[30] The CSPP was approved by the Federal Energy Regulatory Commission (FERC) and its requirements are formulated in Attachment Y of NYISO's Open Access Transmission Tariff (OATT). The objective of CSPP is to ensure reliable operation of the grid on a long term basis. Under the CSPP, NYISO publishes a series of planning documents using model simulations, benefits-cost analysis and policy analysis. These documents are meant to help market participants, regulators and policy makers to plan for the future NYISO system trends. In addition to CSPP, transmission projects are also proposed through interregional planning conducted with NYISO's neighboring control areas (ISOs/RTOs) under the Northeastern ISO/RTO Planning Coordination Protocol. As part of the Order 1000 stipulation, the NYISO participates in interregional planning and may also consider Interregional Transmission Projects in its regional planning processes (RPP). The planning process is represented in Figure 7.

The CSPP is comprised of four components:

- Local Transmission Planning Process (LTPP),
- Reliability Planning Process (RPP),
- Congestion Assessment and Resource Integration Study (CARIS), and
- Public Policy Transmission Planning Process.

The first component of the CSPP is the local transmission planning process (LTPP). Under this process, the local Transmission Owners (TOs) perform transmission studies for their transmission areas according to all applicable criteria. This process produces the Local Transmission Owner Plan (LTP), which is then used to inform the NYISO's determination of system needs through the CSPP.

The second component in the CSPP cycle is the Reliability Planning Process (RPP). RPP requirements are formulated in Attachment Y of the OATT. RPP is a biennial process. Under this process, the reliability of

[30] All NYSIO information in this section is derived from the following sources, unless mentioned otherwise:
NYISO (2015), Reliability Planning Process Manual. Accessed at:
http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/rpp_mnl.pdf
RNA (2014). NYISO Reliability Needs Assessment (RNA). Accessed at:
http://www.safesecurevital.com/pdf/2014%20RNA_final_09-16-2014.pdf
CRPP (2014). NYSIO Comprehensive Reliability Planning Process. Accessed at:
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2015-04-07/2014%20CRP_DRAFT_20150330.pdf

the New York bulk power system is assessed, Reliability Needs if any are identified, generic solutions to identified needs are proposed and evaluated for their viability and sufficiency to satisfy the identified needs, and the more efficient or cost-effective transmission solution to the identified needs if any is shortlisted by NYISO. NYISO's reliability planning process was initially approved by FERC in December 2004 and was revised later in 2014 to conform to FERC Order No. 1000. The RPP consists of two studies:

- **Reliability Needs Assessment (RNA):** This study evaluates the resource adequacy and transmission system adequacy and security of the New York bulk power system over a ten year Study Period. Through this study, the NYISO identifies Reliability Needs in accordance with applicable reliability criteria. This report is reviewed by NYISO stakeholders and approved by the Board of Directors.
- **Comprehensive Reliability Plan (CRP):** After the RNA report is complete, the NYISO solicits market-based solutions to satisfy the Reliability Need. The NYISO also identifies a responsible transmission owner (TO) to submit a regulated backstop solution. Any interested entities are eligible to submit alternative regulated solutions to address the identified Reliability Needs. The NYISO evaluates the viability and sufficiency of the proposed solutions to satisfy the identified Reliability Needs. It then evaluates and selects the most efficient or cost-effective solution to the identified need. In the event that market-based solutions do not materialize to meet a Reliability Need in a timely manner, the NYISO reserves the right to use a regulated backstop solution(s) to satisfy the need. The NYISO develops the CRP for a ten year Study Period. Each biennial CRP report sets forth its findings regarding the proposed solutions for the upcoming ten years. The CRP is reviewed by NYISO stakeholders and approved by the Board of Directors.

Other Transmission Technical Studies

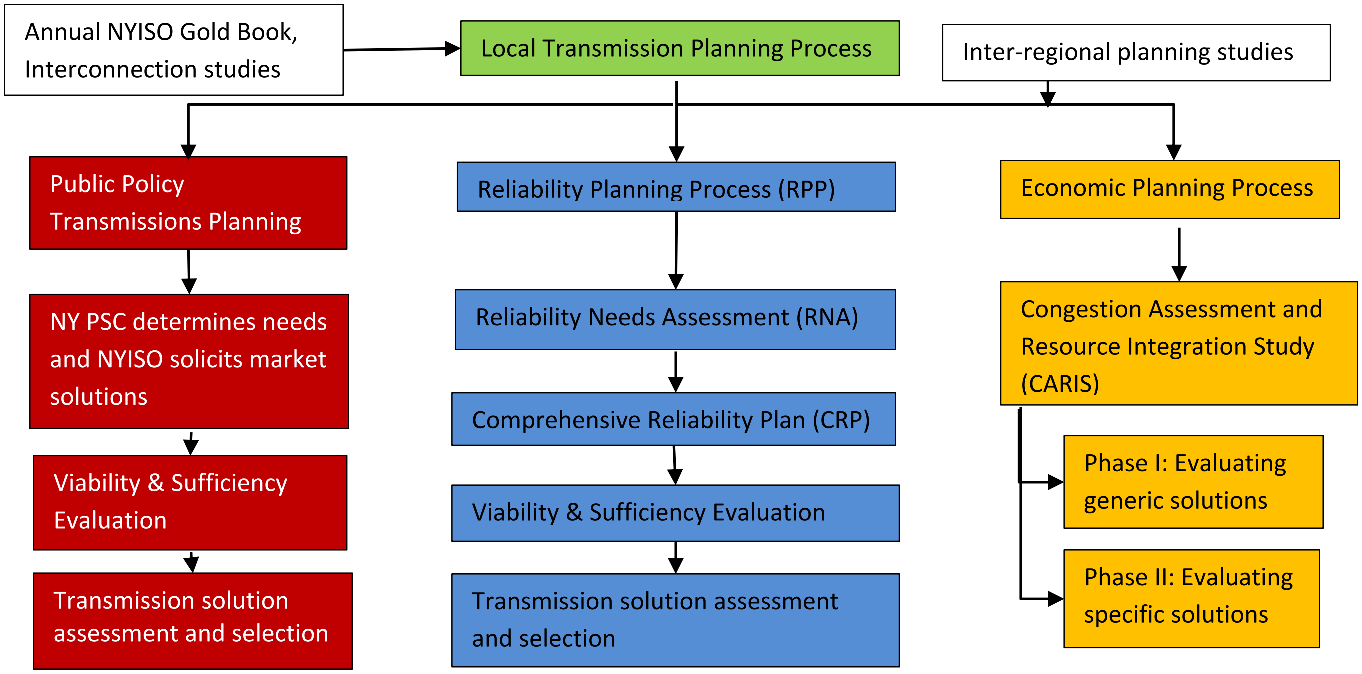
Economic Studies

The third component of the CSPP is the economic planning study. NYISO performs the Congestion Assessment and Resource Integration Study (CARIS) to assess congestion and resource adequacy on a ten year horizon. The CARIS study utilizes the finalized results from the viability and sufficiency assessment portion of the CRP process as its starting basis. The CARIS study is executed in two phases. The CARIS Phase 1 examines congestion on the New York bulk power system, and the costs and benefits of generic alternatives to alleviate that congestion. During the CARIS Phase 2, the NYISO evaluates specific transmission project proposals for regulated cost recovery.

Public Policy

Under this process, transmission needs driven by public policy requirements are identified and interested parties propose solutions. A public policy requirement in NYISO's tariff is defined as a "federal or state law or regulation, including a PSC rulemaking order adopted after public notice and comment under state law that drives the need for transmission." NYISO evaluates the viability, sufficiency, and cost effectiveness of the proposed solutions and develops the Public Policy Transmission Planning report, which is reviewed by NYISO stakeholders and approved by the Board of Directors.

Figure 7 Representation of NYISO's transmission planning process



Reliability Study Models

Base Case Development

NYISO uses the power flow case from prior RNAs as the starting basis. It then uses the Base Case from the most recent FERC Form 715 filing to create a "baseline" for all relevant system models. NYISO reviews the plans and other information collected as part of the input phase of the RPP and subjects them to the RNA inclusion rules. The inclusion rules screen for projects to be included in the upcoming Base Case for the study period. In general, the Base Case inclusion rules include projects with an approved system impact study, executed contracts and other major regulatory approvals. All transmission owner initiated local transmission projects for non-bulk transmission facilities are also included in the Base Case.

The transmission topology assumptions are sourced from the latest FERC 715 filings by NYISO and constituent transmission owners (TOs). Depending upon the extent of changes included in the Base Case, there could be violations of criteria on both the non-bulk and bulk power systems, even under normal base conditions prior to contingency assessments. If these violations are explicitly on the non-bulk power system (i.e. a local problem or "load pocket"), certain generic facilities (including generation or transmission elements) are added to the system model to complete the Base Case. These generic additions are meant for analytical purposes only and are expected to be of a minimal nature. These generic additions may be required for a solvable power flow case and could be removed, modified or separately identified at the conclusion of the RNA process. Scheduled inter-area transfers modeled in the base case between the NYCA and neighboring systems are held constant under all Base Cases and sensitivity cases.

Interface Loading

Based on the input assumptions, interfaces may not be stressed to their limits in NYISO's transmission planning studies. Some of NYISO's transmission owners, however, assess system performance under stressed transmission loading conditions. For example National Grid adjusts generation dispatch to stress selected portions of the transmission system in its local transmission planning process. Transmission projects developed from the local transmission plans of transmission owners are included in NYISO's base case.

Furthermore, NYISO also conducts a "New Capacity Zone" study to evaluate if any of the major interfaces into one or more Load zones is constrained, which may require the creation of a new capacity zone to resolve the generation deliverability issue and meet the reliability need locally. Establishing a new capacity zone helps in providing market signals for generators to respond to reliability requirements in the (new) capacity zone. NYISO conducts this study in the following manner and tests the transfer capability across all of NYISO's major interfaces:[31]

> *All generators in the exporting zone(s) are uniformly increased (scaled) proportional up to the Pmax of all generators in the exporting zone(s) while all generators in the importing zone(s) are decreased uniformly to their minimum power levels. The transmission constraints for the exporting zone(s) are noted for each export/import.*

Load Modeling

Energy demand and system peak data is sourced from the latest NYISO Gold Book. In most of the RNA simulations, a 50/50 coincident summer peak load forecast is used (as projected in the Gold Book). For select sensitivity cases, a 90/10 forecast is also used for contingency analysis. The assumptions on economic growth, energy efficiency program impacts and retail solar PV impacts are primarily sourced from the latest NYISO Gold Book. They could be subject to change depending on the review process by NYISO's Energy Systems Planning Working Group (ESPWG) and the Transmission Planning Advisory Sub-Committee (TPAS). NYISO uses similar reports from neighboring systems to update the data representing those regions.

A 90/10 load forecast is used in specific scenarios to assess the reliability needs and identify any additional violations when compared to the Base Case. The 2014 RNA reports that the 90/10 forecast for the statewide coincident summer peak is on average approximately 2,400 MW higher than the baseline 50/50 forecast. This higher load would result in the earlier occurrence of the reliability needs identified in the Base Case, as well as the possibility of occurrence of new violations in the NYISO region.

Generation Modeling

Generator units that are in-service or under construction and regulated solutions identified in prior assessments are included in the Base Case. Generator retirements and mothballed units are removed from the Base Case in accordance with the effective dates of notices provided to NYDPS and NYISO.

[31] NYISO 2013 New Capacity Zone Study Report, January 14, 2013, page 4.

Power Flow Analysis

The transmission reliability assessment involves steady state and dynamic simulations for normal system conditions and contingencies. Steady state analyses of the bulk power system consists mainly of power flow simulations, contingency analyses (both thermal and voltage aspects) and voltage collapse analysis. Simulations of the system under dynamic conditions include voltage stability and angular stability (including oscillatory damping). The transmission system analyses also include determination of power transfer limits over the ties to external systems and the interfaces within NYCA. The objective of these contingency analyses is to determine transmission reliability needs based on security criteria, calculate independent emergency transfer limits for all monitored interfaces and develop transfer limits and joint interfaces groupings for use in the GE Multi Area Reliability Simulation (GE MARS) resource adequacy model. Violations of local TO criteria and Reliability Criteria violations that are clearly distinguishable as not impacting the bulk power system are not identified as Reliability Needs. When violations occurs on both the bulk and non-bulk power systems, the non-bulk power system violations are mitigated first and the impact on the bulk power system is reevaluated to determine if a Reliability Need still exists.

Contingencies listed by NYSRC Reliability Rules can be broadly classified under two categories – design criteria and extreme contingencies. Design criteria contingencies include single-element and multiple-element. Design Criteria Contingencies are mandatory and broadly correspond to NERC TPL 001-003 standards involving N-1 and N-1-1 contingencies. Extreme contingencies are not required by NERC and are usually tested for long-term planning purposes. They generally correspond to NERC TPL-001-004 standards. The design criteria contingencies include the loss of single element, common structure, stuck breaker, generator, bus, and/or HVDC facilities. An N-1 violation occurs when the power flow on the monitored facility is greater than the applicable post-contingency rating. N-1-1 analysis evaluates the ability of the system to meet the design criteria after a critical element has been lost. Multiple element contingencies allow for corrective actions including generator re-dispatch, phase angle regulator (PAR) adjustments and HVDC adjustments between the first and second contingency.

For any Reliability Needs identified through this process (including through resource adequacy analyses), various amounts of compensatory MW required to mitigate those needs are identified. Compensatory MWs are identified both for bulk power transmission security violations and for resource adequacy violations. But the methodology to quantify the compensatory MWs is different for the two cases. For Reliability Needs identified through security assessment, the compensatory MWs are quantified by calculating transfer distribution factors (TDF) on the overloaded facilities. The power transfer used for this calculation is created by injecting power at existing buses within the zone where the violation occurs, and reducing power at an aggregate of existing generators outside of the area.

For the 2014 RNA, approximately 1,000 design criteria contingencies were evaluated. Overall, the 2014 RNA analyzed the risk to bulk power transmission facilities (BPTF) under certain sensitivities and scenarios to assist market participants in proposing market-based and regulated reliability solutions and also to inform policymakers on the anticipated long-term trends in the New York power system. The following sensitivity and scenario conditions were implemented for the 2014 RNA:

- Dunkirk Fuel Conversion Project
- High (Econometric) Load Forecast

- Indian Point Energy Center Plant retirement
- Zonal Capacity at Risk scenario
- Transmission security under 90/10 Forecasted Load
- Stressed Winter Scenario

The RNA report identified resource adequacy and transmission security needs in the ten year modeling horizon. The resource adequacy needs were identified as early as 2020 for select up-state zones in New York (Zones A and C). Likewise the 2014 RNA identified a list of transmission security violations with a need year arising as early as 2015. The solutions to identified security violations ranged from returning potentially retiring generation resources to service to re-conductoring of transmission lines. The 2014 reliability planning process for NYISO identified no major generation or transmission solutions to resolve the identified Reliability Needs.

Chapter 5: PJM Interconnection

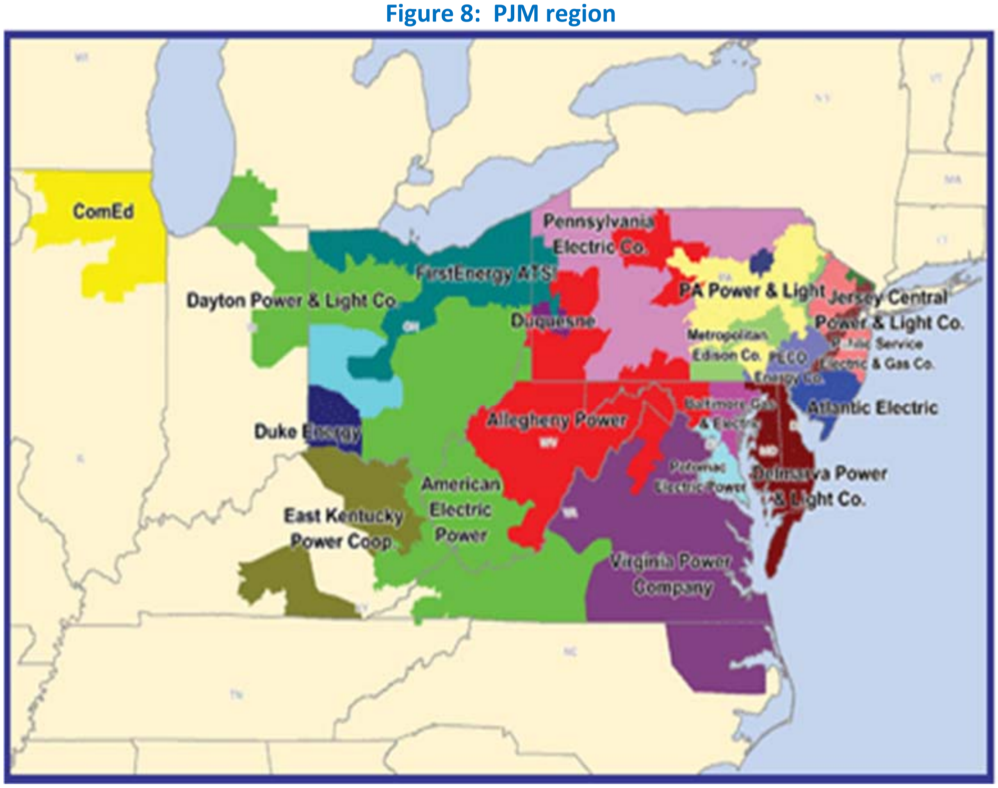
Overview

PJM Interconnection is the regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of thirteen states and District of Columbia in the U.S Northeast. In fact, PJM was the nation's first fully functioning RTO in 2001. PJM, headquartered in Audubon, PA, is currently the world's largest competitive wholesale electricity market. An independent ten member PJM Board of Managers oversees the business operations, regulatory affairs, power markets and reliability aspects of the power grid under PJM's control.

Operating Footprint

PJM Interconnection is a regional transmission organization (RTO) that coordinates the sale, purchase and delivery of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM operates over 62,556 miles of transmission and 183 GW of generation, serving over 61 million customers.

Figure 8: PJM region



Source: FERC

Transmission Planning Process

PJM's Regional Transmission Expansion Planning (RTEP) process identifies transmission system upgrades and enhancements required to maintain grid reliability and economical operation of the wholesale markets.[32] PJM's RTEP process looks at a 15 year planning horizon to determine the transmission needs driven by load growth, capacity resource adequacy, generation resource integration, market efficiency, public policy and operational performance requirements. The RTEP process culminates in a single recommended portfolio of transmission projects for the entire PJM footprint. The recommended portfolio of projects is then reviewed by the PJM Board of Managers. Once the projects are approved the Board, the recommended facilities and upgrades will formally become part of PJM's overall TEP. Board approval also obligates the designated entities to implement the recommended upgrades.

As part of RTEP, PJM implements four types of studies. They include reliability planning, economic planning, interconnection planning, and local planning. PJM conducts reliability and economic planning for all related upgrades for all facilities above 100 KV. For facilities below 100 KV and not under PJM operational control, local transmission owners (TOs) conduct the study. Generator and merchant transmission requests for interconnections and rerates as well as requests for long-term firm transmission service would be considered in interconnection planning. To summarize, PJM's RTEP analyses includes:

- Baseline reliability analyses: to guarantee the security and adequacy of the transmission system;
- Generation and transmission interconnection analyses: to ensure deliverability in the local area for resources or merchant transmission;
- Market efficiency analyses: to assess the economic value of proposed transmission enhancements;
- Operational performance issue reviews: to evaluate PJM transmission development needs based on recent actual operations
- The final RTEP Plan: identifies the most effective and efficient expansion plan for the region to meet requirements for a reliable, economic and environmentally acceptable system.

Transmission Planning Studies

Consistent with the NERC TPL Reliability Standards, PJM's reliability planning includes a near term plan with a 5 year planning horizon (Year 1-5) and a long term plan with a 15 year (Year 6-15) planning horizon. The 24-month reliability planning process includes two 12-month planning cycles to identify and develop shorter lead-time transmission upgrades and one 24-month planning cycle to identify and develop longer lead-time transmission upgrades.

The first step in this process is the development of a set of assumptions, which are vetted with the various internal stakeholder groups at PJM. A series of power-flow base cases are then developed. The yearly series of cases include the latest information and assumptions related to load, resources and transmission topology. There are seven elements to be developed in an annual near-term reliability review: a reference system power flow case; baseline thermal; baseline voltage; load deliverability-thermal; load

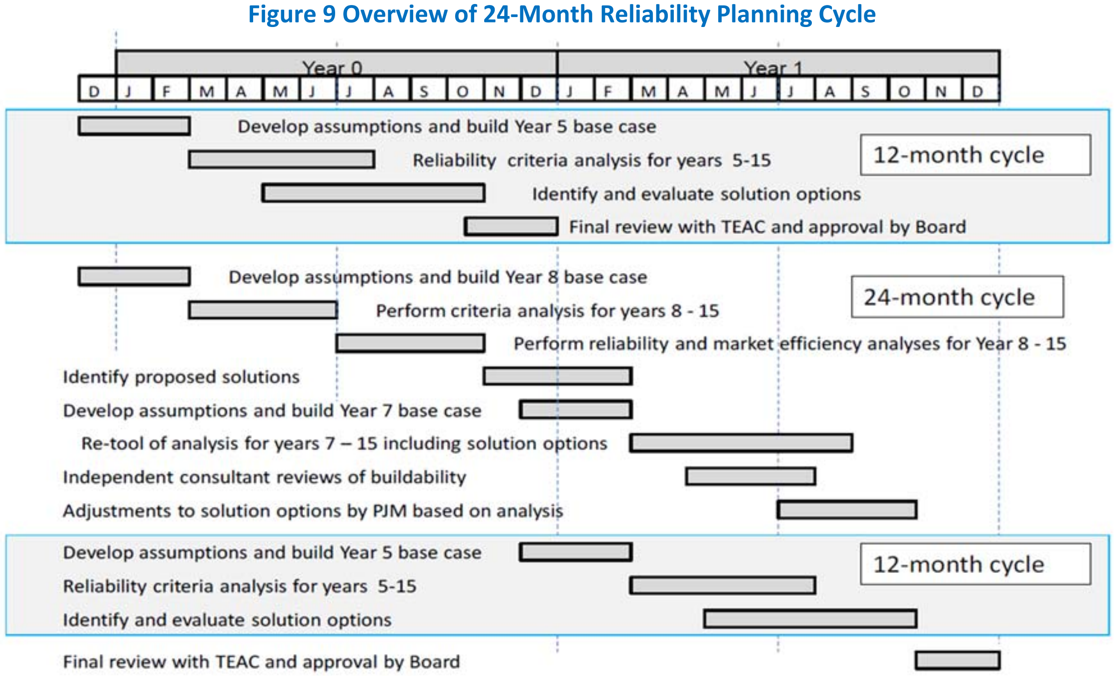
[32] All PJM information in this section is sourced from the following sources, unless specified otherwise.
PJM RTPP (2015). PJM Regional Transmission Planning Process. Accessed at:
https://pjm.com/~/media/documents/manuals/m14b.ashx
PJM RTEP (2015). PJM Regional Transmission Expansion Plan (RTEP). Accessed at:
http://pjm.com/~/media/documents/reports/2015-rtep-process-scope-and-input-assumptions.ashx

deliverability-voltage; generator deliverability-thermal and baseline stability. These elements are then used in a scenario analysis that tests the robustness of the RTEP under variations in key parameters.

In addition to these near-term base cases, additional power-flow base cases are developed for long-term planning. These long-term cases are used to evaluate the need for more significant projects requiring a longer lead-time to develop. These longer lead time projects generally provide benefits that are regional in scope. The long-term base case developed at the start of each 24-month planning cycle is based on the system conditions that are expected to exist in year eight. This year eight base case is updated and retooled at the start of the second year to account for the findings from the analysis that was conducted during the first year of the 24-month planning cycle.

The scope of the near-term baseline analysis includes an exhaustive review of applicable reliability planning criteria on all bulk energy systems facilities. Any identified criteria violations are reviewed with stakeholders throughout the process. Ultimately, solutions to address the criteria violations are developed and reviewed with the relevant internal stakeholder groups. The baseline system without any criteria violations is then used in subsequent planning studies such as the interconnection and market efficiency studies. Long term criteria analysis is completed on the year eight base case during the first year of the 24-month cycle. A combination of a full AC power flow solution and linear analysis is used to determine the loading on a long term basis. Potential solutions to address these long term criteria violations are also identified and added into the RTEP planning pipeline. The 24-month reliability planning cycle is illustrated in Figure 9.

Figure 9 Overview of 24-Month Reliability Planning Cycle



Source: PJM RTEP (2015)

Reliability Study Models

Base Case Development

PJM develops its base cases from the most recent set of Eastern Reliability Assessment Group (ERAG) system models. PJM revises the model to incorporate the current system parameters and assumptions, which include current loads, installed generating capacity, transmission and generation maintenance, system topology, and firm transactions. The 2015 RTEP involves a total of seven base cases. A single base case was implemented for the near-term analysis and the rest were implemented for long-term analysis. PJM's baseline reliability analyses utilize 50/50 and 90/10 load forecasts. The system voltage and thermal analysis use 50/50 load forecasts, while load deliverability tests us 90/10 load forecasts. The contingency definitions used in RTEP analysis are the same as applicable NERC TPL contingency definitions.

PJM adjusts generation dispatch to stress the cases for its load deliverability and generation deliverability studies. The load deliverability test ensures that each load area has adequate transmission capability to import generation required to meet its reliability needs. The test determines the amount of emergency power that can be reliably transferred to the study area from generators in the rest of PJM and areas adjacent to PJM in the event of a generation deficiency in the study area.[33] This limit is compared to the import capability required to meet the reliability objectives of the study area to determine if system improvements are required to maintain reliability.

The generator deliverability test ensures that the transmission system is capable of delivering the aggregate system generation capacity and meeting all firm transmission service during the peak. Areas defined for the generator deliverability test are unique to each study. The areas are defined based on the transmission element that may limit transfers from a set of resources. The cluster of generators with a significant impact on a potential limiting transmission element forms the area for that element. The test ensures that there is sufficient transmission capability in all areas for each area to export its capacity during the peak and avoid any bottled generation.

Interface Loading

For the load deliverability study, PJM develops a base case for each study area that stresses the interface limits into the study area. To achieve the desired import levels, PJM adjusts generation dispatch using a probabilistic assessment when conducting a thermal analysis and a deterministic assessment when conducting a voltage analysis.

Load Modeling

PJM's power flow models are developed from a set of assumptions regarding load, generation and transmission. The load assumptions for PJM are derived from its customized model. PJM's load forecast model produces a 15-year forecast assuming normal weather for each PJM zone and the RTO. The model uses anticipated economic growth and weather conditions to estimate growth in peak load and demand.

[33] At present, load deliverability study areas consist of individual zones, sub-zones and the geographical combinations of zones. Twenty seven zones and sub-zones have thus far been identified. The zones correspond to the present power flow areas of the PJM operating companies. Five global study areas which are geographical combinations of power flow zones have thus far been identified. (Source: PJM Region Transmission Planning Process, Manual 14B, Revision: 31, Effective Date: December 31, 2015.)

Updates to the models from recent PJM regional studies are considered if necessary. As part of load forecast development, PJM uses the results of its latest forward capacity auctions to adjust the unrestricted load forecast to account for demand resources and energy efficiency. This peak load forecast is then used in the development of RTEP power flow models.

For the near-term reliability review, the load deliverability test ensures transmission system adequacy to meet each load area requirement from the aggregate of system generation. The thermal limit test develops an "expected value" of loading after testing an extensive array of probabilistic dispatches that are developed randomly based on availability data for each generating unit. A single failure event in 25 years standard is used for the transmission system reliability criterion. This test uses a 90/10 summer load forecast and considers select NERC contingencies as well. For voltage criteria, a deterministic dispatch is considered and all criteria are the same as those performed for the baseline voltage analyses. The generation deliverability test ensures sufficient transmission capability in all areas of the system to export an amount of generation capacity at least equal to the amount of certified capacity resources in each area.

Generation Modeling

PJM models all existing generation, generators expected to be in service for the year being studied, generators that have signed Interconnection Service Agreement (ISA) or executed Facilities Study Agreement (FSA)[34], and generators that have cleared Base Residual Auctions (BRA). Generators that have officially notified PJM of de-activation are modeled offline in the RTEP Base Case (after the deactivation date). Demand side resources and energy efficient that have cleared the forward capacity auctions are also modeled in the RTEP Base Case.

Power Flow Contingency Analysis

The ERAG system model is used to develop power flow contingency cases. This test insures that all facilities remain in normal rating conditions prior to contingencies and emergency ratings. It considers exhaustive analysis of all N-0, N-1 and N-1-1 events required by NERC, and the most critical common mode outages. For NERC category A, all facilities are loaded with their normal rating and for NERC category B, all facilities are loaded with their emergency thermal ratings. For a single contingency, after allowing phase shifter, re-dispatch and topology changes, post-contingency loadings of all facilities should be within their applicable normal thermal ratings. For more severe NERC category C contingencies, with allowing transformer tap and switched shunt adjustment enabled, post contingency loading of all facilities should be within their applicable emergency thermal ratings.

Similar to thermal analysis, voltage criteria for all the same NERC N-0, N-1 and N-1-1 events are also verified during the contingency testing. Both voltage drop and absolute voltage criteria are tested. Voltage drop is calculated as the amount of reduction in bus voltage from steady state power flow to post-contingency power flow. For voltage drop testing, all phase shifters, transformer taps, switched shunts, and DC lines are locked for the post-contingency solution, both SVC's are allowed to regulate and fast

[34] Generation with an executed FSA will be modeled off-line but will be allowed to contribute to problems in the generation deliverability testing

switched capacitors are enabled. For the absolute voltage testing, the same contingency is set by allowing transformer taps, switched shunts and SVC's to regulate, locking phase shifters and allowing generators to hold steady state voltage criteria.

N-1-1 analysis is based on a 50/50 non-diversified summer peak. The first step in this analysis verifies that all facilities remain in their emergency ratings immediately following the first N-1 contingency. The next step ensures that all facilities remain within their normal thermal ratings after the first N-1 contingency and subsequent re-dispatch and system adjustments. The third step is to evaluate the second N-1-1 contingency. After the occurrence of an N-1-1 contingency that is selected from the optimized N-1 scenario case, long-term or short-term ratings of all facilities should remain within their emergency thermal ratings. Voltage drop tests and voltage magnitude tests follow the same method, except for the voltage drop test, all monitored facilities are checked for the emergency voltage drop limit after the second contingency. The first N-1 contingency includes all Bulk Electric System (BES) single contingencies specified by NERC, as well as lower voltage facilities that are monitored by PJM Operations.[35] Non-BES contingencies, defined by Transmission Owners, need to be considered to check for greater than 300 MW load loss. System adjustment that are allowed after the first contingency are listed below as stated in the PJM planning manual.

For the thermal analysis in the load deliverability study, a mean dispatch case is derived from 10,000 generation outage scenarios that meet the stressed import objective. For the voltage analysis, a deterministic approach based on generator outage rates is used to achieve the import objective. An outage pattern resulting in more severe reliability problems is used if accepted by both the Transmission Owner (in PJM territory) and PJM.

For the generator deliverability study, PJM conducts power flow and contingency analyses and monitors all transmission element for thermal and voltage violations to determine whether contingencies can overload any element. PJM identifies the most impactful generator for each element that could be potentially overloaded. For each of these transmission elements, PJM turns on and ramps up the generator that has the most severe impact to its maximum output. This is continued in turn for each successive impactful generator until there is at least a 20% probability, based on the generator forced outage rates, that the selected generators could all be online and operating at the same time. PJM determines the system improvements required to resolve thermal or voltage violations if any are found. Solutions cannot be dropped load or special protection systems.

PJM performs the generator deliverability test for years 1 through 5, and scales the results of the year 5 study out through year 15.

[35] As defined by NERC, the Bulk Electric System generally includes all transmission elements operated at 100 kV and above (excluding radial components) and transmission elements rated 100 kV or below that may affect transmission components of the electric system.

Chapter 6: Midcontinent Independent System Operator, Inc.

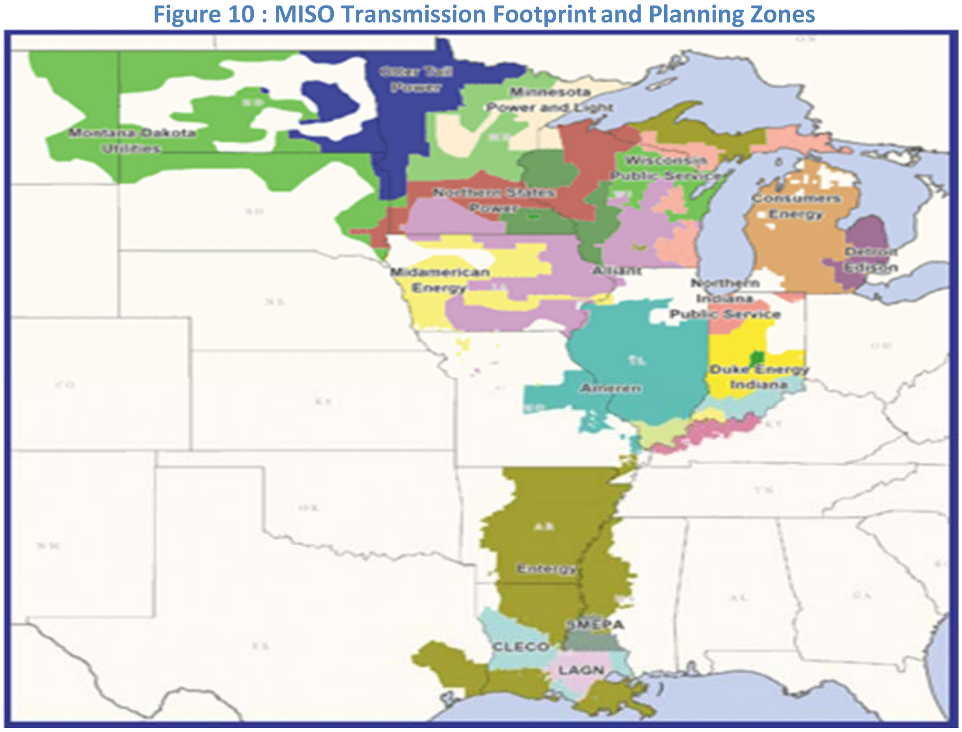
The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit Independent System Operator (ISO) and the Regional Transmission Organization (RTO) that today provides open-access transmission service and monitors the high voltage transmission system in fifteen states throughout the Midwest United States, and Manitoba, Canada. MISO operates one of the world's largest real-time energy markets. MISO was established in 1998 as an ISO and was approved as the nation's first RTO by FERC in 2001. The organization is headquartered in Carmel, Indiana with operation control centers in Carmel, Indiana, Eagan, Minnesota and Little Rock, Arkansas.

Operating Footprint

As of 2014, MISO services provide benefits to approximately 42 million end-use customers through its 391 market participant members representing approximately $2.3 billion in gross market charges. The system managed by MISO has a recent system peak of approximately 132,893 MW served by 201,390 MW of installed generation capacity. For 2007 through 2014, MISO estimates that its members realized between $10.1 billion to $13.7 billion in cumulative savings. MISO estimates that in 2014 its members received more than $2.1 billion as well as significant qualitative benefits from price transparency, seams management, and planning. The southern region of MISO, which covers much of Arkansas, Louisiana, Mississippi, and Texas was integrated into the regional market in December 2013.

MISO conducts transmission planning efforts across a large geographic area. As of September 2015, MISO's Network Model contained more than 289,821 SCADA data points and 6,427 generating units on its network. The system contains more than 65,800 miles of transmission and serves load generated by more than 42 million customers.

Figure 10 : MISO Transmission Footprint and Planning Zones



Source: FERC

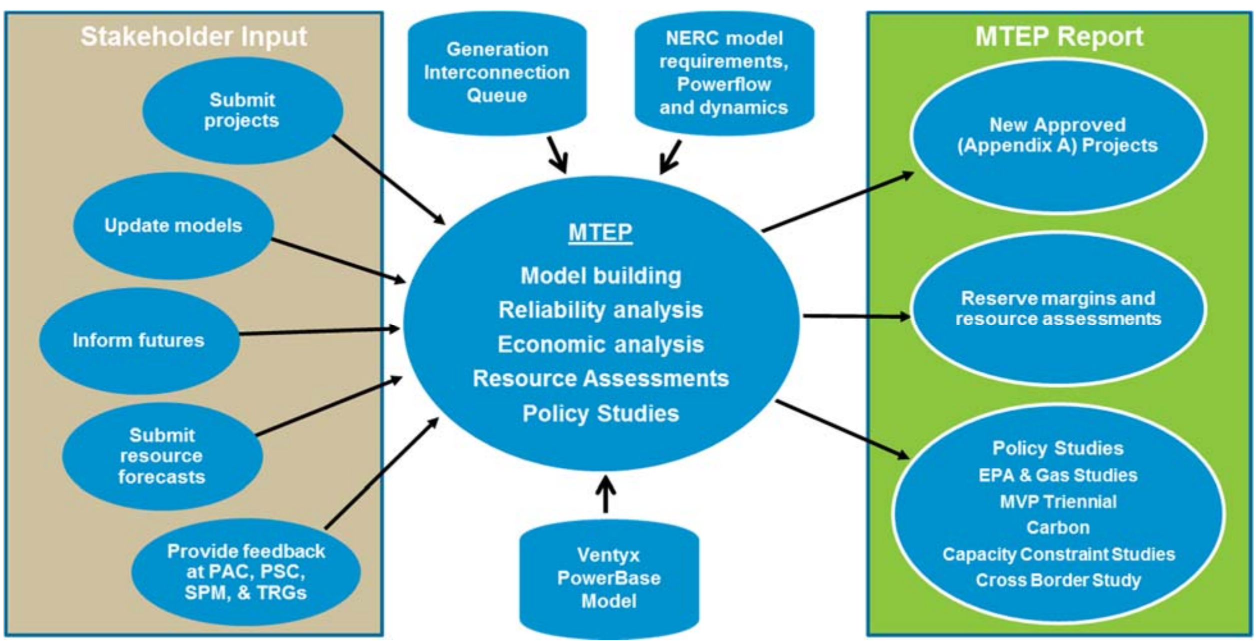
Transmission Planning Process

Transmission Reliability Studies

Within MISO, there are sub-regions referred to as control areas or local balancing authority (LBA) areas. MISO also serves as the NERC Planning Authority for its member footprint, and performs regional planning in accordance with FERC Planning Principles delineated in Order 890. Regional planning in MISO integrates the local planning processes of its member companies into a coordinated regional transmission plan (RTP) and identifies additional expansions. The MISO Transmission Expansion Plan is referred to as MTEP. Since 2003, through the MTEP process, more than $8.4 billion in new transmission projects were approved, constructed, and are now in service. In MTEP14 (2014), 369 projects were approved representing an estimated $2.5 billion in investment. Across current and past MTEP process, 8,400 miles of new and upgraded lines are anticipated through 2023.

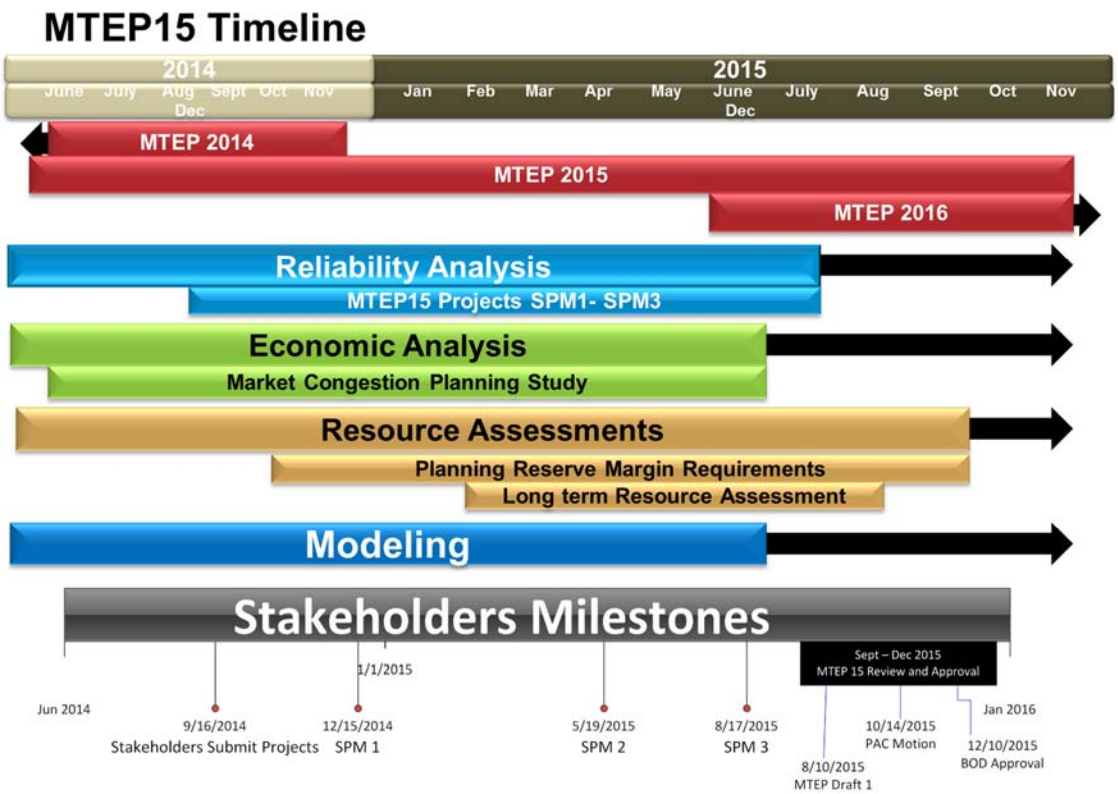
MISO, through the regional planning process, integrates the local planning processes of its member companies and the advice and guidance of stakeholders into a coordinated regional transmission plan and identifies additional expansions as needed. The typically 18-month cycle starts when stakeholders submit newly proposed projects in September. MISO evaluates these proposed projects for inclusion in the MTEP Report. The following year, MISO typically submits a proposed MTEP Report to its Board, and the Board returns its approval in December. The projects listed in Appendix A of the MTEP Report constitute the essential transmission projects recommended to the MISO Board of Directors bi-annually basis for review and approval. MISO distinguishes between different types of projects and evaluates them on reliability, economic, and public policy criteria.

Figure 11 : MISO MTEP Transmission Planning Inputs and Outputs



Source: MISO MTEP (2015)

Figure 12 : MISO MTEP15 Timeline



Source: MISO MTEP (2015)

MISO considers both bottom-up and top-down projects. Bottom-up projects include transmission projects classified as "Other Projects" (OPs) and "Baseline Reliability Projects" (BRPs), are not cost shared, and are generally developed by Transmission Owners (TOs). MISO evaluates all bottom-up projects submitted by TOs and validates that the projects represent prudent solutions to one or more identified transmission issues. Top-down projects include transmission projects classified as Market Efficiency Projects and Multi-Value Projects. Regional or sub-regional top-down projects are developed by MISO working in conjunction with stakeholders to address regional economic and/or public policy transmission issues. Interregional top-down projects are developed by MISO and one or more additional planning regions in conjunction with stakeholders to address interregional transmission issues. Interregional projects are cost shared per provisions in the Joint Operating Agreement and/or MISO tariff, first between MISO and the other planning regions, then within MISO based on provisions in Attachment FF of the MISO tariff.

- **Multi-Value Project (MVP)** meets requirements to provide regional public policy, economic and/or reliability benefits. Costs are shared with loads and export transactions in proportion to metered MWh consumption or export schedules.
- **Market Efficiency Project (MEP)** meets requirements for reduction in market congestion. MEPs are shared based on benefit-to-cost ratio, cost and voltage thresholds.

Externally-driven projects are projects driven by needs identified through customer-initiated processes under the Tariff:

- **Generation Interconnection Project (GIP)** is an upgrade that ensures the reliability of the system when new generators interconnect.
- **Transmission Delivery Service Project (TDSP)** is required to satisfy a transmission service request. The costs are generally assigned to the requestor.
- **Market Participant Funded Project** represents a transmission project that provides benefits to one or more market participants but does not qualify as a Baseline Reliability Project, Market Efficiency Project or Multi-Value Project. These projects are not cost shared through the MISO tariff.

Other Transmission Technical Studies

Additional studies are also routinely conducted and detailed in the Expansion Planning document:

- Voltage Stability.
- Dynamic Stability.
- Long-Term Economic Study
- Seasonal Transmission Assessment
- Resource Assessment
- Generation Deliverability
- Load Deliverability
- System Support Resource
- Coordinated System Plans
- Regional Generation Outlet
- Top Congested Flowgates

From time to time, additional specialized, one-time studies are conducted to augment and improve the primary MISO Process. This year, for example, a study was conducted comparing two transmission expansion options that could facilitate the incorporation of new and existing hydro facilities located in the Manitoba Hydro service territory with the current and planned wind generation in the remaining MISO footprint. The results of this study could warrant additional MTEP project recommendations.

Reliability Study Models[36]

Base Case Modeling

The Base Case models represent a planning horizon spanning the next 10 years. For example, the current MTEP15 will examine transmission planning from 2015 – 2024. Base Models are created for five- and 10-year out horizons, for peak and off-peak critical load conditions. MISO also studies planning horizon Year

[36] All MISO information in this section is sourced from the following reports unless mentioned otherwise:
MISO MTEP (2015). Accessed at: https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP15.aspx
MISO BPM (2015). MISO Business Process Manual- Transmission Planning. Accessed at:
https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/LOLEWG/2013/20130717/20130717%20LOLEWG%20Item%2007d%20BPM-020-r9%20Transmission%20Planning%20Redline.pdf

2 summer peak. The Base power flow case is developed through Model on Demand (MOD) data furnished by member entities, the Ventyx PowerBase database, the latest Eastern Reliability Assessment Group's (ERAG's) models, and MISO member power flow data.

For MTEP15, MISO developed regional power-flow models, model base cases, and sensitivity cases as required by the new TPL-001-4 standard as described in the following table.

Table 6 : MISO MTEP Base Case and Sensitivity Power-Flow Models (as of 11/2015)

Model Year	Base Case Power-Flow Models	Sensitivity Power-Flow Models
Year 2	2017 Summer Peak (Wind at 14.7%) TPL requirement R2.1.1	2017 Light Load (minimum load level) (Wind at 0%) TPL requirement R2.1.4
Year 5	2020 Summer Peak (Wind at 14.7%) TPL requirement R2.1.1	2020 Light Load (minimum load level) (Wind at 90%) TPL requirement R2.1.4
Year 5	2020 Summer Peak (Wind at 14.7%)	2020 Summer Shoulder (70-80% peak) (Wind at 90%) TPL requirement R2.1.4
Year 5	2020/21 Winter Peak (Wind at 30%) MISO MTEP model	Not required
Year 10	2025 Summer Peak (Wind at 14.7%) TPL requirement R2.2.1	Not required

Economic study models developed for use in the MTEP economic planning process are forward-looking, hourly models based on assumptions discussed and agreed upon through the stakeholder process. A scenario-based approach is used to assess a range of futures that provide an array of outcomes that are significantly broad, rather than a single expected forecast. For example, for MTEP15, the Planning Advisory Committee (PAC) approved the following future scenarios:

Table 7 : MISO MTEP Economic Study Future Scenarios (as of 11/2015)

Central and North Regions		South Region	
Business As Usual	BAU	Business As Usual	BAU
High Growth	HG	South Industrial Renaissance	SIR
Limited Growth	LG	Generation Shift	GS
Generation Shift	GS	Public Policy	PP
Public Policy	PP		

The approved MTEP transmission are modeled as in the base power flow model. MISO evaluates flowgate and interface limits, but does not adjust base case dispatch to stress interfaces to their limits. Firm transfers to other regions are typically modeled.

Load Modeling

MISO's load forecast is based on seasonal load projections provided by member companies to the MISO MOD system. A 50/50 weather normalized load is typically modeled. MISO procured an independent vendor, State Utility Forecasting Group (SUFG), to develop three 10-year horizon load forecasts. SUFG provides data used to develop an independent regional load forecast for the MISO Balancing Authority (BA). The first 10-year forecast (2015-2014) was delivered in November 2014. If the (50/50) load projection for a service territory is exceeded more than once historically, MISO will test demand increases up to a (90/10) forecast for the near-term horizon.

Generation Modeling

Existing and planned generators with signed Generation Interconnection Agreements are modeled by in-service dates. Generators that are not network resources are modeled offline. Proxy generation resources from the interconnection queue are used for unplanned generation resources required for future load growth. MISO models retirements based on public announcements from generators (posted in MISO OATT Attachment Y notices).

The generation dispatch in steady-state power-flow models is done at the Local Balancing Area (LBA) level. Network Resource (NRIS) type generation is dispatched in an economic order to meet the load, loss and interchange level for each LBA. The area interchange for each LBA is determined by the transaction table agreed upon by transaction participants, and the generation is dispatched to account for the cumulative MISO net area interchange level. Wind generation is typically an energy resource; however, wind generation is dispatched in models to address renewable energy standards. Wind generation is dispatched at capacity credit level in summer peak models and average and high levels in off-peak models, where:

- 14.7 percent is the wind capacity credit based on MISO's Loss of Load Expectation study.
- 40 percent represents the average wind output level.
- 90 percent represents the high wind output level.
- 30 percent represents the wind output level in the winter model.

Power Flow Analysis

The reliability analysis uses a no-harm test to determine the impact of project candidates on the thermal and voltage stability of the system under select NERC Category B and C contingencies. A project candidate passes the reliability no-harm test if there is no degradation of system reliability with the addition of the project. The no-harm test compares the contingency analysis results between two models, a base model and a model including the project candidate, to find if any violations are worsened by the addition of the project candidate.

The no harm test is performed on four cases:

- Five-year-out Summer Peak.
- Five-year-out Shoulder Peak for North/Central and five-year-out Winter Peak for South.
- 10-year-out Summer Peak.

The input of LBA dispatch is the generation and load profile data submitted by members in the MOD system. Output of generators is determined considering several factors such as seasonal output variations, equipment limitations, policy regulations, approved retirements and local operational guidelines for reliable grid operation. Behind-the-meter generation, hydro machines and non-MISO generation information is retained from generation and load profiles submitted in MOD. Energy resources are not dispatched except for wind resources as described above.

Chapter 8: Southwest Power Pool SPP

Overview

The Southwest Power Pool (SPP)[37] is the RTO serving the Southwest region of the U.S. SPP provides a portfolio of services to members in 14 states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. SPP's membership is comprised of investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers and independent transmission companies.

Operating Footprint

SPP ensures the reliable supply of power, adequate transmission infrastructure, and competitive wholesale electricity prices for a 575,000-square-mile region including more than 56,000 miles of high-voltage transmission lines. The SPP power grid is synchronously connected with other states as well and, therefore, is under Federal Energy Regulatory Commission (FERC) jurisdiction. Prior to the recent integration of the WAPA Upper Great Plains region, the SPP system had the characteristics outlined in Table 8 . The SPP footprint, and hence planning footprint, is reflected in Figure 13.

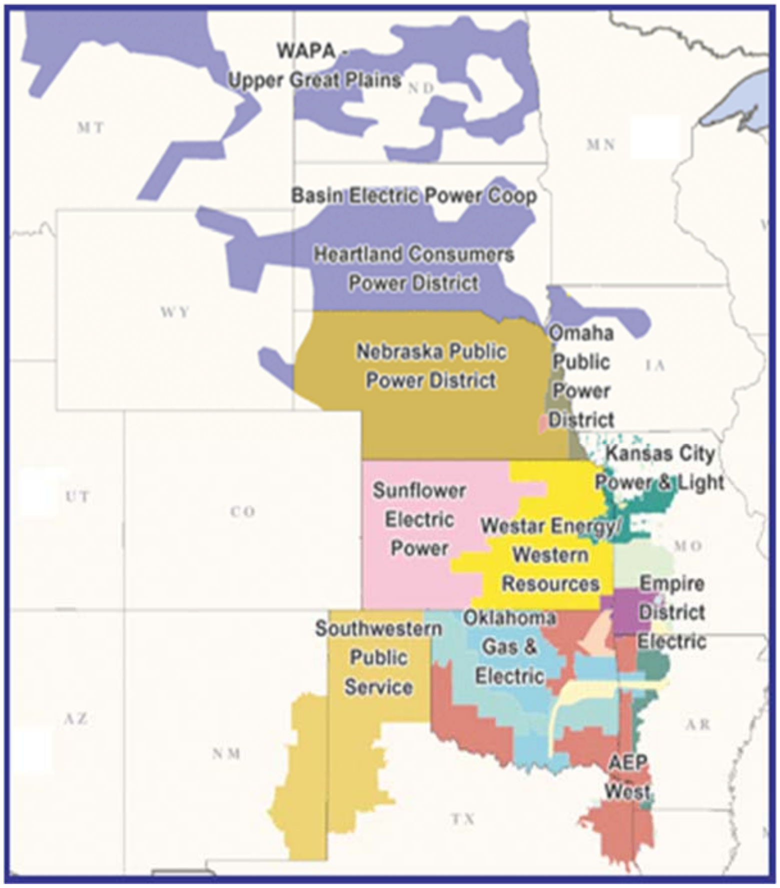
Table 8 SPP Summary Statistics

Customers, 2013	**15.5 million**
Households, 2013	6.2 million
Area Served	575,000 square miles
Generating Capacity (Nameplate), 2015	78,935 MW
All-Time Market Peak	47,142 MW
Coincident Peak Demand (2014)	45,301 MW
Annual Energy Delivery (2014)	234.6 TWh
Existing Transmission Miles (2015)	56,000
Number Members SPP, 2015	93
Coal Share of Generation Capacity (2014)	35%
Wind Share of Generation Capacity (2014)	12%
Demand Resources (2014)	1,284 MW
Annual Planning Capacity Requirement	12%

Source: SPP

[37] All SPP transmission planning information is sourced from the following reports, unless mentioned otherwise.
SPP ITP Manual (2015). SPP Integrated Transmission Planning Manual. Accessed at:
http://www.spp.org/documents/28615/2015%20itp%20manual.pdf
SPP ITPNT (2015). Integrated Transmission Planning Near Term. Accessed at:
http://www.spp.org/documents/30445/final_2015_itpnt_assessment_bod_approved.pdf
SPP ITP10 (2015). Integrated Transmission Planning 10-year Assessment. Accessed at:
http://www.spp.org/documents/26141/final_2015_itp10_report_bod_approved_012715.pdf
SPP ITP20 (2013). SPP Transmission Expansion Plan Report. Accessed at:
http://www.spp.org/documents/19053/2013stepreport.pdf

Figure 13 : SPP Footprint (Including Upper Great Plains)



Source: FERC

SPP's generating capacity is approximately 78,935 MW. This amount includes over 9,000 MW of wind capacity, primarily in western Texas, Oklahoma, and Kansas. These three states are among the top six producers of wind power nationally. SPP generating capacity includes 825 units with an extensive installed capacity of coal and natural gas units. Due to the intermittency of wind and solar units, the amount of capacity available to meet the planning reserve margin target is significantly less.

Transmission Planning Process

Transmission Reliability Studies

SPP utilizes two major processes to develop its transmission plans. The SPP Transmission Expansion Plan (STEP) is a comprehensive listing of all transmission projects in SPP for a 20-year planning horizon. Projects in the 2015 STEP (published in January, 2015) include:

- Upgrades required to satisfy requests for Transmission Service;
- Upgrades required to satisfy requests for Generation Interconnection;
- Approved projects from the 10-Year and Near Term Assessments;
- Approved Balanced Portfolio upgrades;
- Approved High Priority upgrades; and

- Endorsed Sponsored upgrades.

The Integrated Transmission Planning (ITP) process is Southwest Power Pool's iterative three-year study process that includes 20-Year, 10-Year and Near Term Assessments.

- The 20-Year Assessment identifies transmission projects, generally above 300 kV, needed to provide a grid flexible enough to provide benefits to the region across multiple scenarios. The most recent 20-year assessment (2013 ITP20) was issued in July, 2013.
- The 10-Year Assessment focuses on facilities 100 kV and above to meet system needs over a ten-year horizon. The report that documents the 10-year Assessment (2015 ITP10) that concluded in December 2014 was issued in January, 2015.
- The Near Term Assessment is performed annually and assesses system upgrades, at all applicable voltage levels, required in the near term planning horizon to address reliability needs. The most recent Near-Term Assessment (2015 ITPNT) was also issued in January 2015.

The ITP process is a primary vehicle used to inform the STEP report. As future study assumptions become more certain, the ITP supports actionable plans to meet real near-term economic and reliability-driven system needs through the ITPNT. In support of stakeholder-identified or SPP-assessed projects, the stakeholder review process leads to endorsement of individual projects that maintain reliability or increase system economy. Collectively, these activities create a planning process to examine the reliability and efficiency of the SPP transmission system for the foreseeable future. These results are tabulated in the STEP document which forms the basis of the regional transmission plan.

The 2015 ITP10 reliability needs assessment was performed in parallel with the economic and policy needs assessments. All needs were identified using four distinct models. Potential reliability projects including those from SPP Staff, DPPs, and Order 890 submittals, were tested individually in the base model. A reliability project was selected if it addressed either a single reliability need at the least cost or the most reliability needs at the least cost.

For the 2015 ITP10, an economic assessment was conducted to develop a list of constraints for use in the SCUC & SCED analysis. Elements that, under contingency, limit the incremental transfer of power throughout the system were identified, reviewed, and approved by the TWG. Revisions to the constraint definition studies included modification of the contingency definition based upon terminal equipment, normal and emergency rating changes, and removal of invalid contingencies from the constraint definition. The constraint list included normal and emergency ratings and was limited to the following types of issues:

- System Intact and N-1 situations
- Existing common right-of way and tower contingencies for 100+ kV facilities
- Thermal loading and voltage stability interfaces
- Contingencies of 100+ kV voltages transmission lines
- Contingencies of transformers with a 100+ kV voltage winding
- Monitored facilities of 100+kV voltages only

- Neighboring areas were also analyzed for additional constraints to be added.

Congestion was assessed on an annual basis for each future considering many variables. Some of these variables change on an hourly basis, such as load demand, wind generation, forced outages of generating plants, and maintenance outages of generating plants. A total of 8,784 hours were evaluated for the year 2024. Relevant congestion of each constraint was identified through the number of hours congested, average shadow prices associated with constraints for all binding hours and average congestion cost across all hours in a single year.

Reliability Study Models

Base Case Modeling

The power flow models used in the ITPNT, ITP20 and ITP10 are developed based on information accumulated from various sources. The power flow model used for ITP10 and ITP20 is based on the latest MDWG model as approved by internal stakeholders at SPP. Data from SPP stakeholders, Tier 1 entities, and data from other entities or RTO's in the Eastern Interconnect are also incorporated into the model. In addition, an SPP power flow model appropriate for the year(s) under study is imported into the economic model so that the transmission topology is up-to-date.

For the ITPNT, the following base cases are implemented: Year 1: Spring light load, Year 1: Summer Peak, Year 2: Summer Peak, Year 5: Spring light load and Year 5: Summer Peak.

The 2015 ITPNT scenarios are built across multiple years and seasons to evaluate power flows across the grid and to account for various system conditions across the near term horizon. The first scenario (S0) contains projected transmission transfers between SPP legacy BA's and generation dispatch on the system. The second scenario (S5) maximized all applicable confirmed long term firm transmission service with its necessary generation dispatch.

Additionally, a Consolidated Balancing Authority (CBA) model scenario was built across the same years and seasons to show the needs on the SPP transmission system as a result of a Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED).The CBA scenario modeled SPP as a single BA and only modeled power transfers across the SPP seams. The CBA scenario utilized the SPP portion of the NERC Book of Flowgates updated with information from the 2014 Flowgate Assessment, 2015 ITPNT transmission topology, and 2015 ITP10 2024 Summer Base F1 Scenario economic dispatch data. Making use of the economic data from the 2015 ITP10 Assessment, an economic DC tool committed units, creating a dispatch to deliver the most economical power around the constraints approved by the TWG. This unit commitment and dispatch was the SCUC/SCED that was applied to the power flow model used to complete the N-1 contingency analysis described in the Steady State Analysis section. The security constrained economic dispatch in the CBA was applied to the SPP footprint only. The rest of the Eastern Interconnection remained unchanged.

The 2015ITP10 study was conducted based on a pair of futures:

Future 1: Business as Usual: This future includes all statutory/regulatory renewable mandates and goals as well as other energy or capacity as identified in the Policy Survey resulting in 11,500 MW of renewable resources modeled in SPP, load growth projected by load serving entities including the High Priority Incremental Loads, and SPP member-identified generator retirement projections. This future assumes no major changes to policies that are currently in place.

Future 2: Decreased Base Load Capacity: This future considers factors that could drive a reduction in existing generation. It includes 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 by 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 conditions. These target reductions were adjusted, as appropriate, based on locational and operational characteristics provided by the unit owners within each zone.

Interface Loading

SPP evaluates cases adjusted for conditions including: (1) to maintain projected transmission transfers between SPP legacy balancing authorities, and (2) to maximize all applicable confirmed long term firm transmission service.

Load Modeling

A base load forecast used for the ITP20 Assessment and ITP10 Assessment is developed by the Model Development Working Group (MDWG) and reviewed by the Transmission Working Group (TWG) and the Energy Systems Working Group (ESWG) at SPP. Load forecast sensitivities are also utilized for the ITP20 assessment. For load on entities outside of SPP, publically available data is used. If such data is not available easily, then publically available information on load growth rate is used to extrapolate the future loads.

Once inputs such as the peak load values, annual energy values, hourly load curves, and hourly wind generation profiles were incorporated into the model, the economic modeling tool calculated the security-constrained unit commitment and security-constrained economic dispatch (SCUC/SCED) for each hour of the model run year. This process led to identifying the study's two reliability hours:

- Summer peak hour –The summer hour with the highest load.
- Off-peak hour – The hour with highest ratio of wind output to load, in order to evaluate grid exposure to significant output from these resources.

The sum of energy used throughout a year, referred to as the net energy for load forecast, was estimated by SPP using annual load factor data provided and approved by the ESWG. Generally speaking, the 2014 generation expansion and transmission economic analysis used the normal weather (50th-percentile) load forecast.

For the IPTNT, future energy usage was forecasted by utilities in the SPP footprint and collected and reviewed through the efforts of the MDWG. This assessment used both summer peak and light load scenarios to assess the performance of the grid in both peak and off-peak conditions. Load Serving Entities provided the load forecast used in the reliability analysis study models through the MDWG model building process.

Generation Modeling

Generation resource assumptions are derived from internal stakeholder inputs. For example, for the latest ITP10, a generator review was conducted with stakeholders. This information includes maximum capacities, ownership, retirements, and other operating characteristics of all generators in SPP. After the required generation additions were determined for each zone, they were sited within the zone based on locations identified for the 2013 ITP20 and HPILS. The ESWG and other stakeholders provided input on potential locations for additional gas generation, along with the associated bus information based on space requirements, proximity to gas pipelines, and existing electric transmission. All existing generation and new generation with interconnection agreements are included in the power flow case. Proxy generation resources are sited at suitable SPP sub-areas (satisfying specified capacity margins and renewables requirements). In general, generation resources includes renewables as well. For ITP10 Futures 1 and 2, resource plans were also developed for external regions. Each region was assessed to determine the capacity shortfall, and natural gas combined cycle and combustion turbine units were added so that each region met its own capacity margin. New units were interconnected to lines with high transfer capacity. Individual projects within the recommended portfolio provided reliability, economic, and policy benefits within Future 1. Projects meeting the performance criteria for Future 1 and Future 2, outlined in Table 9, were included in the recommended portfolio.

Table 9 : SPP Consolidation Criteria (as of 11/2015)

Project Type	Future 1 Performance	Future 2 Performance
F1 Reliability	Mitigate a thermal or voltage violation	N/A
F2 Reliability	Mitigate 90% thermal or 0.92 pu voltage limit	Mitigate thermal or voltage violation
F1 Policy	Meet a policy need	N/A
F2 Policy	N/A	N/A
F1 Economic	1-year B/C ≥ 0.9	N/A
F2 Economic	1-year B/C ≥ 0.7	1-year B/C ≥ 0.9

Projects mitigating more than one type of need were evaluated against multiple performance criteria. Only one set of criteria is required to be met for a project to be included in the recommended portfolio. AC models were developed for each of the two hours in each future. An N-1 contingency scan was performed for the SPP, IS, and Tier 1 footprints to determine thermal and voltage criteria violations, defined as system reliability needs.

Generation in the ITPNT cases is modeled in accordance with the ITPNT process document and the ITP10 process. The initial generation dispatch information of all existing conventional generation (natural gas, coal and nuclear) is retained from the start cases initially but may be re-dispatched to relieve transmission overloads. Wind, solar and hydro units are dispatched according to the guidelines specified in the process document. Future generation units are added to the start cases and dispatched according to their resource type.

Power Flow Contingency Analysis

For the IPT10, power flow models were developed and identified reliability needs based on analysis of four hours representing situations where the transmission system was uniquely stressed. The four hours considered include two different futures, with Future 1 representing Business as Usual and Future 2 representing a Decreased Base Load Capacity. Facilities 69 kV and above were monitored to identify needs in the SPP RTO and Tier 1 footprints. Potential violations, in accordance with the SPP Criteria or SPP member criteria, if more restrictive, were identified in each of these hours during the N-1 contingency scans, and labeled as reliability needs. The voltage level for potential violations could be 69 kV, but projects that addressed these potential violations were no lower than 100 kV.

The ITPNT is designed to evaluate the near-term reliability and robustness of the SPP transmission system, identifying needed upgrades through stakeholder collaboration. The ITPNT focuses primarily on solutions required to meet the reliability criteria defined in OATT Attachment O Section III.6. Unlike the ITP10 and ITP20, the ITPNT is not intended to focus on solutions based on a preferred voltage level, but to effectively solve all potential reliability needs in their entirety. The 2015 ITPNT process produces a reliable near-term plan for the SPP footprint which identifies solutions to potential issues for system intact and single contingency (N-1) conditions using the following principles:

- Identifying potential reliability-based problems consisting of NERC Reliability Standards for normal and N-1 contingency conditions, SPP Criteria and where applicable, local SPP Member criteria.
- Utilizing Transmission Operating Guides.
- Developing additional mitigation plans including transmission upgrades to meet the region's needs and maintain SPP and local SPP Member reliability/planning standards.

In the course of the reliability modeling, facilities in the SPP footprint 69 kV and above were monitored for exceeding 90% thermal loading or voltage below 0.95 per unit. Needs are generated at 100% thermal loading or voltage below 0.9 per unit for non-base case conditions and voltage below 0.95 per unit for base case conditions. All facilities in first-tier control areas were monitored at 100 kV and above. System intact (base case) and N-1 contingency analysis was performed on SPP facilities at 69 kV and above and at 100 kV and above for Tier 1 control areas in the 2015 ITPNT models. After performing the initial reliability assessment identifying the bulk power problems, thermal and voltage needs were posted for stakeholder accessibility.

Appendix

Table 10 Comparison of ISO/RTO Transmission Planning Reliability Studies

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
ISO/RTO Overview[38]							
No. of TOs	7	16	8	50	8	50	16
States Spanned	CT, ME, MA, NH, RI, and VT.	CA, NV	TX	AR, IA, IL, KY, LA, MI, MN, MO, MS, MT, ND, NE, SD, TX, and WI.	NY	DE, IL, IN, KY, MD, MI, NJ, NC, OH, PA, TN, VA, WV and DC	AR, IA, KA, LA, MO, MN, MT, ND, NE, NM OK, SD, TX and WY
Approximate Peak Demand, 2014 GW)	25 GW	47 GW	67 GW	127 GW	29 GW	141 GW	49 GW
Population Served	14 million	30 Million	24 million	42 million	19.5 Million	61 Million	15 million
Miles of High Voltage Transmission	8,500	26,000	43,000	65,800	11,000	62,500	50,575
Transmission Planning Overview							
Planning Cycle	Annual	Annual	Annual	Annual	Bi-Annual	Annual	Triennial with annual near-term assessment
Planning horizon	Year 1- 10	Year 1 or 2; Year 5; Year 10	Year 1; Year 3; Year 4 and Year 5.	Year 1; Year 2; Year 5 & Year 10.	Year 1- 10	Year 5 & Year 15	Year 1; Year 10 and Year 20
Primary Modeling Tools	Siemens PSS/E (power flow analysis); PowerGEM TARA (security assessment); ABB/Ventyx GridView (production cost)	GE-PSLF (reliability) GridView (economic)	Siemens PSS/E for power flow analysis; PowerWorld for AC SCOPF analysis; PowerGEM TARA for contingency analysis; UPLAN for economic analysis.	Siemens PSS/E for power flow; and PROMOD for economic studies; EGEAS for resource planning	GE MARS (Resource Adequacy) Siemens PSS/E and PowerGEM TARA (security assessment); GE MAPS & ABB/Ventyx GridView (production cost simulation).	PowerGEM TARA (security assessment) Siemens PSS/E (power flow studies) ABB/Ventyx PROMOD (production cost)	Siemens PSS/E for power flow and dynamic models; ABB/Ventyx PROMOD for economic modeling

[38] See ISO-RTO Council - http://www.isorto.org/About/Members/allmembers

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
Reliability Models							
Source of power flow seed case(s)	Power flow Base Case is sourced from Model on Demand (MOD) Base Case. This includes the model of external system by Multi-regional Modeling Working Group (MMWG) (data furnished by member entities).	Power flow Base Cases are developed by the Western Electricity Coordinating Council (WECC) Planning Coordination Committee.	ERCOT's Steady State Working Group (SSWG) develops the cases based on inputs from transmission service providers (TSPs). Using Network Model Management System (NMMS), ERCOT and TSPs create the steady-state models that represent the current and planned system conditions.	MISO uses Model on Demand (MOD) Base Case (data furnished by member entities); Ventyx PowerBase database; latest Eastern Reliability Assessment Group's (ERAG's) models; MISO member power flow data.	NYISO uses the most recent FERC Form 715 filing as the starting point for the Base Case	PJM uses ERAG MMWG Base Case and other assumptions by RTEP	SPP's Model Development Working Group (MDWG) develops the power flow cases based on inputs from SPP stakeholder, first tier neigbors and other entities or RTOs in the Eastern Interconnect.
Summary of cases developed and analyzed	For each study area, multiple base cases are developed with variations in generation outages and interface loadings. Conditions examined include 90/10 Summer Peak, Intermediate Load (approximate value actual system loads were at or below 90% of the time), Light Load (approximate value actual system loads were at or below for 2,000 hours), Minimum Load (set just below actual	For each year multiple base cases are developed to assess 17 study areas (current planning cycle), including multiple base cases for individual areas with variations in load and dispatch assumptions. **Base case conditions examined include:** 2nd Year: Summer Peak, Spring Off-Peak, Winter Peak; 5th Year: Summer Peak, Spring Light Load, Winter Peak; 10th Year: Summer	Regional Transmission Plan (RTP) cases include: Year 1: Summer Peak Year 3: Min. Load Year 3: Summer Peak Year 4: Summer Peak Year 5: Summer Peak	5 Base Cases and 3 Sensitivity cases (current planning cycle) **Base case conditions examined include:** 2nd Year: Summer Peak (Wind at 14.7%); 5th Year: Summer Peak (Wind at 14.7%); 5th Year: Summer Shoulder (70% peak and wind at 40%); 5th Year: Winter (wind at 30%) **Sensitivity cases:**	A single Reliability Needs Assessment (RNA) Base Case is developed for reliability assessment (for the current planning cycle). Sensitivities examined include fuel conversion and generation retirements Scenarios examined include High load econometric forecast (peak forecast excluding	7 Base cases – One near term Base Case and 6 longer term Base cases. Additional cases developed for each study area for load deliverability and generator deliverability studies Baseline thermal and voltage reliability analysis is based on a 50/50 load forecast (minus energy efficiency). Baseline load deliverability study	**ITPNT cases:** Year 1: Spring light load Year 1: Summer Peak Year 2: Summer Peak Year 5: Spring light load Year 5: Summer Peak

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
	minimum system loads) Sensitivity analysis is conducted to assess the impact of the inclusion or exclusion of particular generation resources, transmission projects, or load, and to determine the impact of changes that could occur within the planning horizon.	Peak, Summer Partial Peak, Spring Off-Peak, Winter Peak **Sensitivity cases:** Sensitivities vary by planning cycle and consider impacts of load forecast, generation dispatch, generation retirement and transfers on major paths for one or more of the planning horizons.		2nd Year Light Load (minimum load level) (Wind at 0%); 5th Year Light Load (minimum load level) (Wind 90%) 2020 Summer Shoulder (70-80% peak) (Wind 90%)	EE); Zonal capacity at risk; Retirements of critical generators (Indian Point); Transmission Security Assessment (TSA) using 90/10 Load Forecast; Stressed winter condition assessment.	based on a 90/10 load forecast. PJM performs scenario analysis to assess the impact of variations in drivers such as regulatory initiatives and generator operational performance.	
Data Sources and Assumptions							
Source of load data assumptions	Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report) and MMWG case for external areas	California Energy Commission (CEC) balancing authority load forecast, augmented by local area load forecasts. The local forecasts developed by CAISO's participating transmission owners are used to develop bus-level load forecasts	SSWG Dataset and ERCOT forecasts. SSWG load datasets are compiled from transmission planners	Seasonal load projections provided by member companies to the MISO MOD system.	Latest NYISO Load and Capacity Report ("Gold Book"); Energy efficiency and demand response projections are sourced through discussions with TOs and other stakeholders of NYISO's Electric Systems Planning Working Group (ESPWG).	Collaborative process between PJM and its members, guidelines set forth by NERC and the ERAG MMWG procedural manual	Load forecast is obtained from SPP stakeholder participation in SPP's Model Development Working Group (MDWG). For load forecast of entities outside of SPP, publically available data is used.
Source of supply resource data assumptions	CELT Report	CEC and California Public Utilities Commission (CPUC)	Sourced from SSWG Start Case (which in turn is developed jointly by Transmission Service Providers (TSPs) and ERCOT).	MMWG models, neighbor updates and MISO member data for MTEP Power flow models.	Latest NYISO Gold Book	ERAG database and PJM member data for RTEP models	SPP stakeholders furnish the relevant non-sensitive resource data assumption (through internal

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
				Data from Ventyx PowerBase; MISO neighbor updates included for MTEP PROMOD model.			SPP working groups).
Source of transmission topology assumptions	ISO-NE RSP for internal facilities and MMWG case for facilities external to the region.	Previous CAISO-approved transmission plans	Sourced from SSWG Dataset. SSWG dataset is compiled annually by TSPs and ERCOT.	MMWG models, neighbor updates and MISO member data for MTEP Power flow models.	FERC 715 Base Case filing	ERAG database and PJM member data for RTEP models	Transmission topology is sourced from SPP members. NERC Book of Flowgates is used as the starting basis for the transmission constraints.
Typical baseline load assumptions	90/10 summer peak load for New England Control Area. ISO NE also examines: Intermediate Load, Light Load, and Minimum Load (as described previously)	90/10 load forecasts are used for local area studies; 80/20 load forecast is used for system studies; light load conditions represent the system minimum load conditions while the off-peak load conditions range from 50 percent to 70 percent of the peak load in an area	The higher of the two load forecasts: (1) Bus load forecast from Annual Load Data Request (ALDR) as developed by TSPs (also incorporated in SSWG dataset); and (2 ERCOT forecast of 90th percentile weather zone load forecast (90/10)	50/50 coincident load projection for each transmission owner (TO) service territory for the study horizon. For fixing the transfer capability limits, MISO tests if the (50/50) load projection for a service territory is exceeded more than once historically. If so, MISO will test demand increases up to (90/10) forecast for the near-term horizon.	50/50 coincident summer peak load forecast (as projected by NYISO Gold Book) A 90/10 load forecast is used in specific scenarios to assess the reliability needs and identify any additional violations when compared to the Base Case.	For the power flow model, PJM uses a load forecasting model involving weather, economic conditions and calendar/solar data. Non-coincident 50/50 peak load forecast is used in baseline thermal and voltage studies (at zonal levels). Baseline load deliverability test is based on 90/10 load level. The sum of zonal coincident peak is used as the PJM RTO peak demand forecast.	A 50/50 (expected) non-coincident peak load for each Load Serving Entities (LSE) is assumed for ITP studies. When load forecast data is not available for a given year in a non-SPP region, publically available information on projected load growth is used to obtain the extrapolated estimates.

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
Typical baseline supply and demand resource assumptions	Generators with capacity supply obligations or binding contracts (state-sponsored RFP or financially binding contract) are included in studies to identify transmission needs and evaluate solutions. Demand response is modeled as negative load in the base case. Passive DR (excluding EE forecast) and Active DR are based on the most recently concluded Forward Capacity Auction (FCA). EE is based on the CELT forecast. PV solar is also based on the CELT forecast. Solar PV generators greater than 5 MW are modeled as individual generators, and those less than 5 MW are modeled as negative loads.	2-5 year planning cases: generation that is under construction and has a planned in-service date within the planning horizon; 6-10 year planning cases: only generation that is under construction or has received regulatory approval; EE and DR assumptions come from forecasts developed by the CEC. RPS portfolios for sensitivity analysis are developed and provided by the CEC and CPUC.	All existing plants and new generation will be used in the study. New generation units with approved interconnection agreements and necessary permits are modeled in the base case. Mothballed units may be placed in service for future years depending on reliability requirements. Dispatch of existing generation units is retained from SSWG Start Cases. The dispatch is subject to change to relieve transmission overloads.	Existing and planned generators with signed Generation Interconnection Agreements are modeled by in-service dates. Generators that are not network resources are modeled offline. Proxy generation resource from interconnection queue is used for unplanned generation resources required for future load growth.	Units that are in-service or under construction and regulated solutions identified in prior assessments are included. Projects with approved system impact study, executed contract, and other major regulatory approvals are included. EE and DR are modeled based on Gold Book assumptions.	All existing generation and generators with Interconnection Service Agreement (ISA) generation. If insufficient to meet the load requirements, then units with Facilities Study Agreement are also considered. All units that cleared in PJM's capacity market are included. Demand resources that have cleared PJM's capacity auctions and energy efficiency resources are included in the assumptions for RTEP development and physically modeled in the baseline power flows	Existing generation and new generation with interconnection agreement. Proxy generation resources are sited at suitable SPP sub-areas (satisfying specified capacity margins and renewables requirements) Resources includes renewables and conventional generation. Applicable capacity margin and renewable requirements are also included.
Typical baseline retirements assumptions	ISO-NE considers generators that have submitted a Non-Price Retirement Request. Other generators considered unavailable are generators that have	Retirements as announced by generator owners or based on assumptions developed in consultation with the CEC and CPUC.	Retired and mothballed units are assumed based on RTP scope.	Publically announced generation retirements (MISO OATT Attachment Y notices)	Publically announced generation retirements	Generators that have officially notified PJM of de-activation are modeled offline in the RTEP Base Case (after the deactivation date).	Publically announced retirements are factored in the resource plan developed by SPP's Energy

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
	an accepted Permanent De-list bid, generators that have delisted in the last two rounds of capacity auctions and generators that are unavailable because of special circumstances such as denial of license extensions or being physically unable to operate.						Systems Working Group (ESWG).
Typical baseline transmission assumptions	Transmission in New England includes facilities in-service, under construction, planned, and proposed projects. Transmission outside New England based on recent MMWG base case.	Existing facilities and previously ISO-approved new builds/upgrades	The base transmission model contain all existing and planned facilities, including reactive power resources and control devices.	Two sets of power flow assumptions: [1] with existing and all prior MTEP projects. [2] With existing, prior and currently targeted MTEP projects.	Existing transmission facilities, TO designated non-bulk power transmission facilities and TO designated bulk power transmission projects under select criteria. The select criteria includes regulated solutions identified in prior reliability assessments; projects required for constituting the Base Case for study period; firm projects with approved system impact studies as proposed by NYPA/ TOs in	PJM models all transmission projects that are approved by the PJM Board and are expected to be in-service before the modeling horizon. The modeled upgrades includes those needed to solve the identified NERC reliability criteria violations caused by generator deactivations.	Approved STEP project and other special projects are added to the power flow model at the start of each study cycle. SPP approved transmission upgrades, transmission owners' zonal upgrades and first tier neighbors' planned upgrades (AECI, Entergy, EC, WAPA) are included in the topology.

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
					local planning or the projects subject to regulatory authorization for TOs to proceed.		
Reliability Studies Performed							
Stressed Base Case conditions (if applicable)	ISO-NE develops a stressed case for transmission needs assessment. The two most impactful generators whose outage create the greatest stress on the area of study are considered out of service. Multiple base cases may be required to determine the most impactful generators.	For each study year CAISO develops several base cases to address conditions in the different study areas within the region. (The 2015-2016 Final Plan considered 17 study areas.) Different bases cases may be developed for different study areas, and multiple base cases may be developed for the same study area (e.g. to assess different load and dispatch conditions).	ERCOT develops a stressed base case for its Regional Transmission Plan (RTP). ERCOT uses adjustments to generation dispatch (including dispatching mothballed resources and increasing the dispatch of variable generation resources) and load scaling outside the study area to adjust interface flows to target levels.	MISO develops multiple base cases to address reliability needs in the near and long term. The system is tested at summer stress conditions (at on-peak and off-peak conditions).	For its reliability needs assessment NYISO develops a base case that is representative of expected system conditions in the study period. NYISO examines stressed scenarios, including high load, retirement, and extreme weather conditions. NYISO also includes planned transmission projects from local transmission plans of transmission owners in its base case.	PJM develops power flow base cases for near-term (1 to 5 year) and long-term (6 to 15 year) assessments. Base cases for baseline thermal and voltage analysis are representative of expected system conditions in the study year. For the baseline load deliverability and generator deliverability studies, base cases are developed with stressed interface limits. For load deliverability test generation dispatch is adjusted using a probabilistic assessment for thermal analysis and deterministic for voltage	SPP develops multiple base cases to address reliability needs in the near and long term. Each base case represents SPP's expected system conditions in the respective study period. The power flow base cases are modified to incorporate the unit commitment, dispatch and load level associated with the specific hour(s) to be analyzed (e.g. summer peak, winter peak, light load, etc.)

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
						analysis. For generator deliverability test, PJM turns on and ramps up the generators that would most impact transmission elements that could become overloaded.	
Base Case Interface Loading Assumptions	Interfaces that may affect the area under study are modeled with transfer levels that cover the full range of existing capabilities. Internal and coincident (surrounding) interfaces associated with a study area are considered individually as well as in combination. Each base case is tested at different interface levels.	For local area studies, transfers on import and monitored internal paths are modeled as required to serve load in conjunction with internal generation resources. Interfaces into the study area are stressed in the base case. For bulk system studies, CAISO stresses its major import and internal transfer paths.	Interfaces into constrained study areas are modeled at their limit. Changes in generation dispatch (including dispatching mothballed resources and increasing the dispatch of variable generation resources) and load scaling outside the study area is used to adjust interfaces to their limits.	MISO evaluates flowgate and interface limits, but does not adjust base case dispatch to stress interfaces to their limits.	NYISO includes planned transmission projects from local transmission plans of transmission owners in its base case. In its local transmission planning process National Grid adjusts generation dispatch to stress selected portions of the transmission system.	For the thermal analysis in the load deliverability study a mean dispatch case is derived from 10,000 generation outage scenarios that meet the stressed import objective. For the voltage analysis a deterministic approach based on generator outage rates is used to achieve the import objective. An outage pattern resulting in more severe reliability problems can be used if accepted by both the Transmission Owner and PJM	SPP evaluates cases adjusted for conditions including: (1) to maintain projected transmission transfers between SPP legacy balancing authorities, and (2) to maximize all applicable confirmed long term firm transmission service.
Steady State Contingencies	ISO-NE analyzes steady state contingencies based on applicable NERC	Contingencies are modeled as per NERC TPL 001-004 standards, including	NERC Category A (normal state with no contingency)	Contingencies are modeled as per NERC TPL 001-004 standards, including	Contingencies are listed by NYSRC Reliability Rules.	NERC Category A (normal state with no contingency)	N-1 contingency analysis is conducted for the peak and off-peak

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
Tested[39] (e.g. N-0, N-1, N-1-1, G-1)	and Northeast Power Coordinating Council (NPCC) requirements (N-1; N-1-1 and extreme events contingencies). ISO-NE analyzes extreme contingencies to determine the effect on the bulk power system. It develops plan or operating procedures to reduce the probability of occurrence or mitigate the consequences. ISO-NE does not build out the system to address the impact of extreme contingencies.	NERC Category P1-P7 contingencies as defined in the Study Plan for all local areas and select areas outside the CAISO controlled grid; Extreme Event contingencies area assessed per the requirements of TPL-001-4, however the analysis of Extreme Events is not included within the Transmission Plan documentation unless the analysis drives the need for mitigation plans to be developed. CAISO also analyzes G-1+N-1 contingencies.	Category B (loss of single element like generator unit, transmission lines and transformers 60 kV and above; systems that remove multiple elements for a single fault) Category C (involving the loss of two successive elements including N-1-1; G-1+N-1; and loss of two circuits on same tower) (C3&C5) Category D (a small subset of multiple element contingencies)	NERC Category A (normal or no contingencies), NERC Category B (N-1), NERC Category C (N-1-1, double circuit outages and various faults), NERC Category D (severe contingencies furnished by transmission owners and NERC supplements by automatically generated contingencies) Contingencies on non-MISO systems are also analyzed for impacts.	They include [1] Design Criteria Contingencies and [2] Extreme Contingencies Design Criteria Contingencies are mandatory and it corresponds to NERC TPL 001-003 standards involving N-1and N-1-1 contingencies. Extreme contingencies provide context for planning and corresponds to NERC TPL 001-004.	Category B (loss of single element) Category C (including N-1-1 contingencies) Contingencies involving most common mode outages	for facilities 60 kV and above in SPP and facilities 100kV and above in first tier neighboring regions. Contingencies involving common right-of-way and tower for 100 kV or higher lines; 100 kV or higher transmission lines; transformers with a 100 kV or higher and monitored facilities of 100 kV and above are modeled in ITP10 & ITP20.
Other studies (e.g. Dynamic, stability)	Transient voltage response; Voltage stability analysis; Short circuit analysis; Transient stability analyses;	Post transient voltage stability analyses; Post transient voltage deviation analyses; Voltage stability and reactive power	Short circuit analysis; Generator and transformer outage analysis	Voltage stability analysis and dynamic stability analysis; Load deliverability studies; Generator	Voltage collapse/voltage stability analysis; Transient (angular) stability analysis;	Stability, load deliverability, and generation deliverability.	Thermal load and voltage stability analysis, Shunt reactive requirements assessment

[39] NERC's Transmission Planning (TPL) Standards define the contingencies that planning entities are required to analyze. TPL-001 through TPL-004 initially defined four categories of contingencies – Categories A through D. Category A assumes all facilities are in service. Category B events result in the loss of a single transmission element and Category C in the loss of two or more elements. Category D events are considered extreme events, and they result in the loss of multiple elements. FERC has approved TPL-001-4 to replace the previous version of TPL-001 and also TPL-002, TPL-003 and TPL-004. In TPL-001-4 events are classified as planning events or extreme events. Planning event contingencies are grouped into 8 categories, P0 through P7, which address contingencies similar to Categories A through C. P0 assumes all facilities are service. P1 and P2 are different categories of single element contingencies, and P3 through P7 are different categories of multiple element contingencies TPL-001-4 extreme events are similar to Category D events. TPL-001-4 would replace all other versions of the TPL Standards by December 31st, 2015.

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
	Voltage deviation.	margin analyses; Transient stability analyses.		deliverability studies	Short circuit analysis		
Contingency Testing							
Method used (deterministic, probabilistic, other?)	Deterministic	Deterministic	Deterministic	Deterministic	Deterministic	Deterministic dispatch method for base line Probabilistic dispatches for load deliverability and risk assessment analysis	Deterministic
How are violations resolved in the simulations?	ISO-NE uses generation re-dispatch and reactive devices to resolve identified violations prior to the second contingency for N-1-1 assessments. ISO-NE may also use operating guides.	Violations are documented together with potential mitigation solutions and reported in the preliminary study results	Reliability projects are identified and modeled in the simulations to resolve any N-1 criteria violations.	For N-1-1 overload, MISO uses re-dispatch, system reconfiguration, operating guides and limited load loss.	For non-bulk power system model adjustment and generation dispatch may be adjusted to resolve the criteria violations and base case convergence requirements.	Violations are resolved by system reconfiguration, generation re-dispatch	ITP NT uses Transmission Operating Guides (TOG) to resolve violations.
What mitigation measures are proposed to eliminate violations identified in the study? (e.g. capital improvement projects)	Regulated transmission solution and market responses to the needs, including investments in resources (e.g., demand-side projects, generation and distributed generation) and Elective Transmission Upgrades.	Violations are mitigated by congestion management; new or modified Special Protection Systems or Remedial Action Schemes; capital improvement projects	ERCOT, in collaboration with transmission owners, compiles a list of reliability/economic projects to resolve the violations. Any remaining violations are mitigated through Congestion Mitigation Plans (CMPs) developed	Transmission solutions developed through MTEP	Market sponsored solutions as well as regulated backstop solutions	PJM identifies potential system reinforcements to resolve the violations. Demand Response that has cleared capacity auctions is modeled in the baseline assumptions.	SPP uses a pool of possible solutions from transmission service studies, generation interconnection studies, previous ITP studies, local reliability planning studies by transmission solutions, stakeholder input and staff evaluation.

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
			with transmission owners.				
Special Considerations							
Use of Scenarios or Sensitivities	Base Case sensitivity for impact of the inclusion or exclusion of a particular resource, transmission project or load	Reliability assessments include scenario/sensitivity analysis to evaluate impacts of modifications to key baseline assumptions as determined by the ISO	2014 ERCOT RTP implemented the followings scenarios A low load to identify N-1-1 constraints in 2017 A scenario without any wind generation A scenario with generation units without SCR removed from service Change of dispatch status of select generation resources (Frontera)	Sensitivity cases in reliability studies include minimum load levels and variable wind penetration factor. Sensitivities in Economic Planning include Business-as-Usual (BAU), High Growth, Limited Growth, Generation Shift, Public Policy and Robust Economy Scenarios.	High Load (Econometric) Forecast Zonal Capacity at Risk Indian Point Retirement Assessment Transmission Security Assessment Using 90/10 Load Forecast Stressed Winter Condition Assessment	**Scenarios:** Winter Peak EPA Clean Power Program	Reliability studies involve cases with seasonal variations. ITP10 has the following cases: [1] F1:Business as usual [2] F2: Decreased base load capacity ITP20 has the following scenarios [1] Business-as-usual [2] Additional Wind [3] Additional wind plus exports [4] Combined policy [5] Joint SPP/MISO Future
Coordination with Resource Planning efforts	Forward Capacity Auction conducted for resources needed to meet demand and reserve margin requirements. ISO-NE's network topology assumption is updated to incorporate upgrades associated with resources that have cleared the FCA.	Resource assumptions are an input into the reliability assessments and are largely informed by the state's resource procurement process. This process is informed by the CAISO's local capacity technical	Resource expansion analysis are evaluated using UPLAN. Resource expansion planning is assessed in the 10-year horizon Long Term System Assessment (LTSA).	For long term planning, the generator resources are adjusted using resource adequacy process. Load deliverability study ensures that the MISO aggregate system and Local Resource Zones	Reliability modeling incorporates the installed capacity requirements set by NY State Reliability Council (NY SRC) & NYISO. Capacity requirements include installed	As part of load forecast development, PJM uses the results of forward capacity auctions to adjust the base unrestricted load forecast to account for demand response and energy efficiency.	Resource planning is carried out in three phases. [1] Phase I: A resource expansion plan is developed for each future scenario using an optimal

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
		studies and other resource adequacy and integration assessments.	The expansion portfolio under different scenarios are assessed for reliability using DC SCOPF. The resource expansion portfolio developed through this process is used to inform ERCOT's annual regional system planning process.	have sufficient capacity to meet 1 in 10 years LOLE reliability criterion. Generator deliverability study ensures that a group of generators in a local area are not bottled up.	reserve margin (IRM) and local capacity requirements (LCR) of New York City, Long Island and Lower Hudson Valley zones.	This adjusted peak demand is used in RTEP power flow models.	generation expansion model [2] Phase II: New resources are sited at suitable locations within SPP footprint. [3] Phase III: Generators are entered in SPP database and connected to suitable buses. Resource assumptions derived through this process is used as an input to the reliability and economic assessment modeling.
Other Related Transmission Studies	Studies to identify Market Efficiency Transmission Upgrades (METUs), which are projects primarily designed to reduce the total net production cost to supply the system load	Economic congestion studies; Generator Interconnection Process (GIP) Network Upgrade Assessments; Long-Term Congestion Revenue Rights Feasibility Studies	Economic analysis (using UPLAN); Annual Report on Constraints and Needs; Long Term System Assessment; Environmental Regulations and Future Electric Reliability (2014).	Market Congestion Planning Study (MCPS); Market Efficiency Planning Study (MEPS); Economic Planning (using EGEAS)	Congestion Assessment and Resource Integration Study(CARIS), New York State Transmission Assessment and Reliability Study (STARS)	Market efficiency Analyses; Baseline Assessments Long-term Studies for Transmission Services	Rate Impact studies; Economic assessment (SCUC and SCED) for model run years
Current Planning Cycle							
Planning Cycle	2015-2016	2015-2016	2015	2015	2015-2016	2015	2015 (ITPNT); 2015 (ITP10); 2013 (ITP20)
Planning Horizon	2016-2025	2017, 2020, 2025	2016,2018, 2019, 2020	2017, 2020, 2025	2016-2025	2015-2020-2029	2016,2017, 2020, 2025, 2033

	ISO-NE	CAISO	ERCOT	MISO	NYISO	PJM	SPP
Current Study Plan	Link	2015-2016 Study Plan	2015 RTP	MTEP 2016	2016 RNA & CRP	RTEP 2016	ITPNT 2016
Most Recent Transmission Plan	Link	2014-2015 Transmission Plan	2014 RTP	MTEP 2015	2014 RNA ; 2014 CRP	RTEP 2015	ITP20 2013; ITPNT 2015; ITP10 2015.

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