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Planning Arrangements for Electricity Transmission Networks: An International Review

A Report for the Australian Energy Market Commission

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1. Introduction

This report has been prepared by NERA Economic Consulting (NERA) at the request of the Australian Energy Market Commission (AEMC).

The AEMC has sought advice on transmission planning arrangements as they apply in other electricity markets, to inform further development and consideration of planning options in the Australian National Electricity Market (NEM).

Specifically, the AEMC has asked for a summary of planning arrangements in the following four North American markets:

- Pennsylvania-Jersey- Maryland (PJM) (covered in Section 2 of this report);
- New York (Section 3);
- California (Section 4); and
- Alberta (Section 5).

For each market we describe:

- The key institutions and entities;
- The overall planning process;
- Roles and responsibilities in relation to investment decision making;
- Arrangements for economic regulation;
- Arrangements in relation to reliability standards; and
- Recent developments.

In addition the AEMC has asked us to summarise the reforms mandated by FERC Order No. 1000 regarding transmission planning, transmission cost allocation, and development of transmission projects by non-incumbents. A summary of these aspects of FERC Order No. 1000 is set out in Section 6 of this report.

The appendices to this report provide further information in relation to the characteristics and functions set out by FERC for Regional Transmission Organisations (RTOs), and the North American Reliability Council (NERC) Transmission Planning Reliability Standards.

2. PJM

Transmission planning in Pennsylvania-Jersey-Maryland centres on a Regional Transmission Expansion Planning (RTEP) process which is carried out by PJM Interconnection LLC (PJM), the Regional Transmission Organisation (RTO)[1] for the region concerned. The RTEP is supplemented and supported (to a limited extent) by planning done by independent transmission owners and merchant transmission investors[2] within the PJM service territory.

The territory of covered by PJM is shown in Figure 2.1 - PJM Service Territory and covers 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.

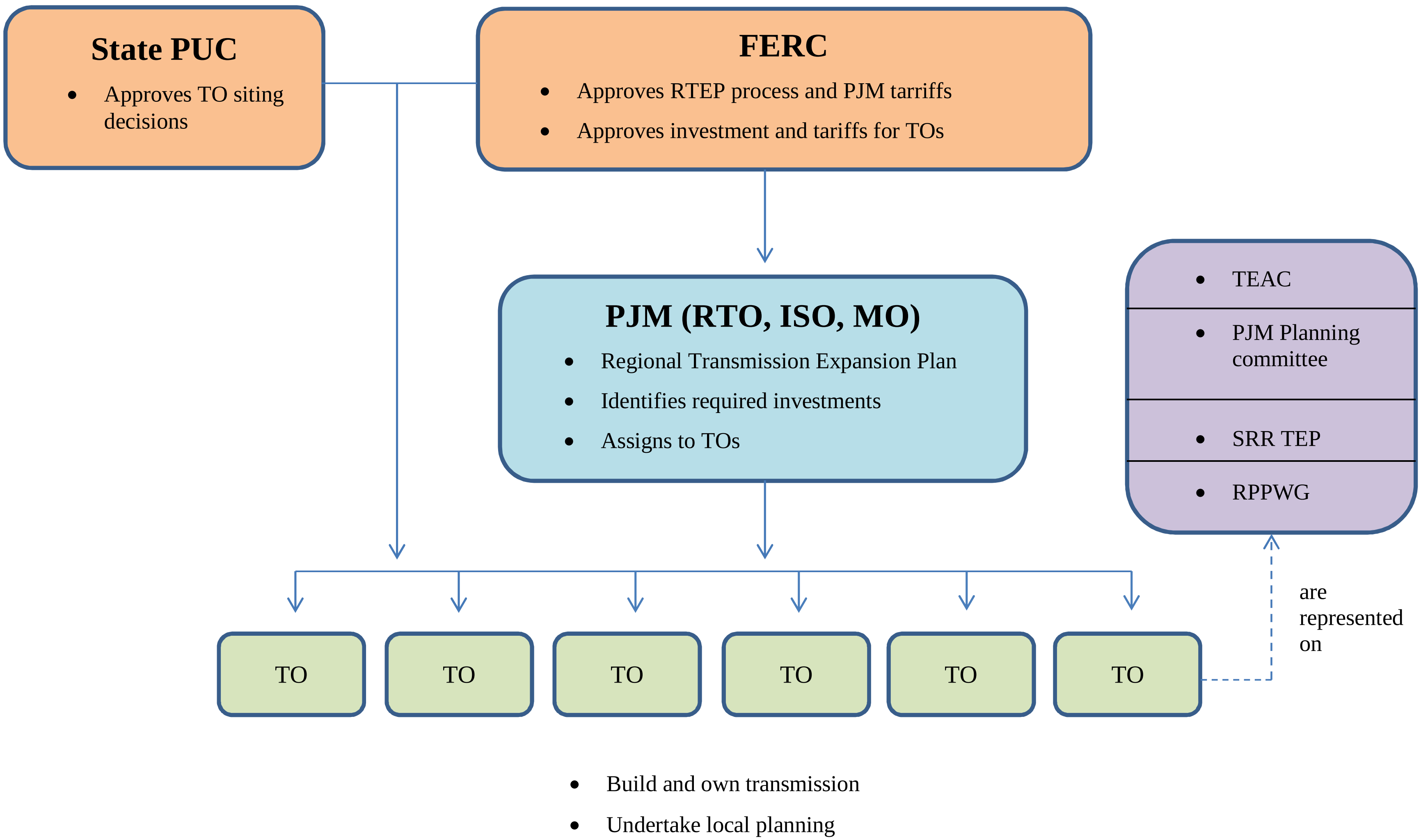
Figure 2.1 - PJM Service Territory

Source: PJM

1 Refer to Appendix 1 for a description of RTOs. We note that in the US the terms RTO and ISO (Independent System Operator) are FERC-defined terms. In practice there is very little different between the legal definitions of each.

2 This refers to an entity which might or might not have a local reliability incentive and which plans and funds specific transmission investments outside of the wider planning process on the basis of an economic objective.

Figure 2.2 - Summary of Key Roles and Responsibilities PJM



2.1. Institutional arrangements

The key institutions and entities within the market relevant to transmission planning are as follows:

- PJM Interconnection LLC (PJM), which is the RTO;
- Transmission Owners (TOs) and merchant transmission investors;
- The North American Electric Reliability Corporation (NERC), together with its regional affiliates;[3]
- The Federal Energy Regulatory Commission (FERC); and
- States Public Utility Commissions (State PUCs) for each of the states listed above.

Other stakeholders include generating companies, Load-Serving Entities (LSEs), [4] land-owners, and others.

The following is a description of the roles of the key institutions and their relationship to each other.

2.1.1. *PJM Interconnection LLC (PJM)*

PJM Interconnection LLC (PJM) is a FERC-approved RTO that coordinates the movement of wholesale electricity within the PJM service territory and is responsible for planning to ensure "efficient, reliable, and non-discriminatory transmission service" throughout the area it serves. The area served by PJM is the largest centrally dispatched grid in North America.

PJM's role is to act independently and impartially in managing the wholesale electricity market and the regional transmission system:

- PJM's short-term responsibilities include system and market operations. PJM is both the Independent System Operator (ISO) and Independent Market Operator (IMO) for the region.
- PJM's long-term responsibilities include regional planning and providing a planning process with a broad, interstate perspective that identifies the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system-wide basis.

One of PJM's long-term FERC-required responsibilities and core functions is to create regional transmission expansion plans. PJM's RTEP identifies transmission system upgrades and enhancements necessary to continue to meet required reliability standards, as well as those transmission investments which are expected to have an overall economic benefit.

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[3] The regional affiliates are ReliabilityFirst Corporation and the Southeastern Electric Reliability Council (refer to Section 2.1.3).

[4] An LSE is anyone who is a buyer of wholesale energy for consumption by end-use customers under the market rules. A retailer is an LSE, and so is a distribution company or the supplier of last resort in a state where retail is not fully competitive. An LSE might also be a large industrial customer who purchases direct from the wholesale market on its own behalf. An LSE is not a marketer, who might buy for (wholesale) resale, or deal only in derivatives.

PJM doesn't build or own transmission. Rather it creates planning models and undertakes studies to determine what new transmission investment will be needed to maintain reliability and provide economic benefit into the future. PJM assesses transmission investment needs from a larger, regional perspective rather than the potentially more limited view of a single TO.

In order to participate in PJM markets, an entity must be a *member* of PJM. There are five categories of full members:[5]

1. TOs;
2. Generation owners;
3. Distribution businesses;
4. End-use customers (normally large consumers who wish to participate directly in the wholesale markets); and
5. Power marketers, including retailers.[6]

By acceding to the PJM membership agreements,[7] members have assigned a number of rights and responsibilities to PJM and have undertaken a number of responsibilities in return. Each category of membership entails a specific set of rights and responsibilities.

PJM is an independent, not-for-profit organisation, incorporated as a limited liability company. PJM has a two-tier governance structure with an independent board and a members committee:

1. The Board is responsible for maintaining PJM's independence and, by exercising their prudent business judgment, ensuring that PJM fulfils its business obligations and legal and regulatory requirements, as well as preventing any market participants from having undue influence over the operation of PJM or exerting market power in PJM markets. The members of the PJM Board must have no personal affiliation or ongoing professional relationship with, or any financial stake in, any PJM market participant.
2. The members committee provides advice to the Board by proposing and voting on changes and new programmes, with the Board having the final say. The committee is composed of five voting sectors representing the five membership categories above. Every member of PJM has a representative on the committee. Only one affiliate of a member corporate entity may vote in the committee. Other committees and groups meet on specific issues and report to the members committee.[8]

[5] It is also possible to be a *non-full* member of PJM. Non-full members generally do not participate in the market, but are stakeholders in electricity market outcomes and so have an interest in PJM's activities. Non-full members include: ex officio regulatory members – federal and state agencies with regulatory authority over a PJM member; ex officio consumer advocate representatives – these representatives hold state office; emergency customer load reduction program special members – these organizations have special membership status for participating in the Emergency Customer Load Reduction Program; and associate members – who have special membership status.

[6] This category is formally known as "other suppliers" and consists of other entities engaged in buying, selling or transmitting electric energy, capacity, ancillary services, financial transmission rights or other services.

[7] Primarily the PJM Operating Agreement, Open Access Transmission Tariff (OATT) and the Reliability Assurance Agreement.

[8] Ex officio regulatory members, emergency customer load reduction program special members and associate members do not have voting rights in the members committee. Associate members do not have voting rights in any stakeholder activities, working groups or committees.

2.1.2. *Transmission Owners (TO)*

TOs are the owners of the physical transmission assets. In most cases they own all or the majority of transmission assets within a particular sub-region of PJM which corresponds to a historical service territory of a vertically-integrated utility prior to industry restructuring. This sub-region is known as a PJM 'zone', and the TO has on-going responsibility for transmission assets within its zone. In some cases TOs are now independent shareholder-owned companies. In others they remain part of a larger shareholder-owned utility that may also own generation, distribution, retail and other businesses. In other cases they may be owned by local governments or authorities. In all cases they are functionally-separated from any non-transmission affiliates and transmission is regulated separately from any such affiliates.

By being a member of PJM and acceding to the membership agreements TOs have assigned the primary regional transmission planning responsibility to PJM and have undertaken to implement PJM's plans.

TOs have the rights and responsibilities associated with transmission construction. PJM is not generally involved with detailed siting decisions e.g., the procurement of easements. Once PJM's studies indicate that transmission is needed between Point A and Point B to meet planning objectives, the exact route to achieve this transmission is determined by the TO(s) in the zone(s) where the geographical need for transmission has been identified and the relevant state PUCs (when required). Cost estimation, siting, and project management, are addressed by TOs through their internal processes and interactions with appropriate regulatory authorities.

TOs own the transmission facilities they build. Each TO is responsible for maintenance of the parts of the network it owns. TOs may also conduct local transmission planning, to supplement the local grid and/or address local transmission issues, which are not covered by PJM in the RTEP.

Finally, there is a special form of transmission owner, known as a *merchant transmission investor*. This refers to an entity which might or might not have a local reliability incentive[9] and which plans and funds specific transmission investments outside of the wider planning process on the basis of an economic objective, such as an arrangement to connect low-cost generator with a higher-priced market. In practice, very few transmission investments are made on a merchant basis.

2.1.3. *NERC*

The North American Electric Reliability Corporation (NERC) develops and enforces reliability standards for the North American bulk power system.[10] As such, the description of NERC in this section is relevant for PJM, New York and California.

9 This means that a merchant transmission investor is not regulated in any way that relates to ensuring reliability, security or capacity adequacy (which other forms of TOs might be). A merchant transmission investor's sole motivation is commercial return, and as such they tend to evaluate each specific new investment on a stand-alone (case-by-case) basis for profitability.

10 The bulk power system, also referred to as the Bulk Electricity System (BES), includes all transmission facilities operated at 100 kV and above, as defined by NERC. PJM also conducts planning and analysis on facilities rated below

NERC's major responsibilities include working with all stakeholders to develop standards for power system operation, including transmission planning reliability standards, monitoring and enforcing compliance with those standards, assessing resource adequacy (done annually via a 10-year forecast) and providing educational and training resources as part of an accreditation program to ensure power system operators remain qualified and proficient. NERC also investigates and analyses the causes of significant power system disturbances in order to help prevent future events.

FERC certified NERC as the national Electric Reliability Organization (ERO) for the United States in 2006.[11] Prior to being the National ERO, NERC's guidelines for power system operation and accreditation were referred to as *Policies*, for which compliance was strongly encouraged yet ultimately voluntary. Since 2006, NERC Policies have been revised into *Standards*, and now NERC has authority to enforce those standards on power system entities operating in the United States, as well as several provinces in Canada, by way of significant financial penalties for noncompliance (of up to $1 million per day per violation).

NERC's role is to oversee the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces mandatory minimum reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. Among its many activities, NERC coordinates critical infrastructure protection and cyber-security and facilitates the exchange of information among reliability organizations.

Included in NERC's certification was a provision to delegate authority for the purpose of proposing and enforcing reliability standards by entering into delegation agreements with regional entities. The geographic scope of these regional entities is illustrated in Figure 2.3 – . Note that there is not a one-to-one correspondence with the geography of RTOs/ISOs.

One of the regional entities, ReliabilityFirst Corporation, covers most of PJM. A smaller portion of PJM is within the territory of the Southeastern Electric Reliability Council (SERC).

NERC is governed by a twelve-member independent Board of Trustees.

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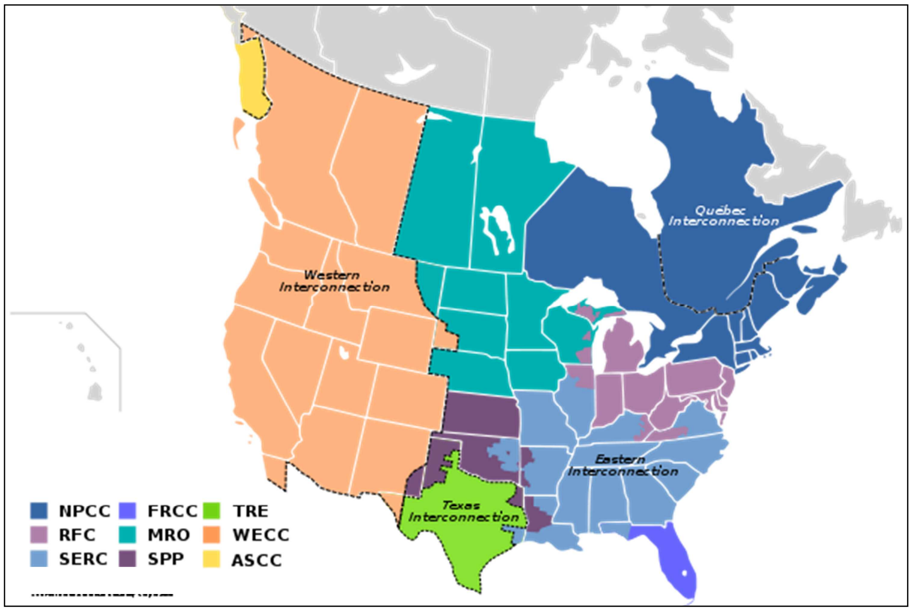
100 kV if the flows on those facilities are under the control of the PJM system operator and impact on flows on transmission facilities rated greater than 100 kV.

11 FERC was given the authority to do this under powers obtained in the Energy Policy Act of 2005, following the 2003 Northeast blackout.

Figure 2.3 – North American Regional Reliability Councils and Interconnections



Source: NERC

2.1.4. *FERC*

The Federal Energy Regulatory Commission (FERC) is the national energy regulator for the United States. As such, the description of FERC in this section is relevant for New York and California, as well as PJM.

FERC's main activities relating to the power industry are as follows:

- Regulation of wholesale sales of electricity and transmission of electricity in interstate commerce;
- Oversight of mandatory reliability standards for the bulk power system;
- Promotion of strong national energy infrastructure, including adequate transmission facilities; and
- Regulation of jurisdictional issuances of stock and debt securities, assumptions of obligations and liabilities, and mergers.

Regarding electric reliability, FERC oversees the development of mandatory reliability and security standards. It monitors and directs the Electric Reliability Organization (i.e. NERC) to ensure compliance with the approved mandatory standards by the users, owners, and operators of the bulk power system.

Regarding transmission investment, FERC's mandate is to promote the development of a strong national energy infrastructure, and it approves the transmission planning processes of PJM and other RTOs/ISOs.

FERC is the economic regulator of RTOs/ISOs and TOs, meaning that it approves individual transmission investments and transmission tariffs. TOs can also be subject to some economic regulation at the state level, i.e. from state Public Utility Commissions, as described below.

Regarding transmission line siting, the Energy Policy Act of 2005 authorized FERC to issue, in limited circumstances, permits for new transmission facilities within National Interest Electric Transmission Corridors designated by the U.S. Department of Energy. In practice this authority is rarely used.

FERC is an independent agency, it has up to five commissioners who are appointed by the President of the United States with the advice and consent of the Senate. Commissioners serve staggered five-year terms, and have an equal vote on regulatory matters. FERC has a staff of over 1,000. All FERC decisions are reviewable by the federal courts.

2.1.5. *State Public Utility Commissions*

State Public Utility Commissions (state PUCs) are the state-level regulators of electric utilities in the USA. State regulation is historically distinguished from federal regulation in the United States by the question of inter-state commerce. Electricity distribution and retail are essentially *within state* activities and are overseen by state PUCs. Transmission, which is increasingly an *inter-state* activity, is largely regulated by FERC.

There is some overlap between federal and state regulation of transmission however. For example, state regulators exercise their rights and responsibilities via some combination of state siting or certificate authority and/or federal and state ratemaking authority. State PUCs typically possess the authority to:

- Disallow imprudent or unreasonable costs in a traditional ratemaking proceeding;
- Impose conditions on siting approval or a certificate of public convenience and require the utility to provide periodic reports on cost estimates for a particular project;
- Intervene in another state's regulatory proceeding as an interested party;
- Intervene before FERC in a rate case (for example if the PUC believes that transmission cost responsibility has unreasonably been allocated to its state by an RTO/ISO such as PJM); and/or
- Review and approve or reject a utility's Integrated Resource Plan (IRP). An IRP is a long-term strategy regarding future energy sources which a state PUC will require utilities to file annually.

2.2. Planning process

Planning for enhancement and expansion of transmission capability on a regional basis in the PJM service territory is led by PJM using its Regional Transmission Expansion Planning (RTEP) process. In summary:

- The RTEP process was developed by PJM and its members under FERC guidance;
- The RTEP process is designed to ensure compliance with NERC standards (and achieve economic efficiency benefits, where identified);
- FERC approved the role of NERC, the role of PJM, the RTEP process, and it approves the individual investments resulting from the RTEP process as well as the resulting transmission tariffs;
- Individual TOs have assigned transmission planning rights and responsibilities to PJM as a condition of PJM membership, and assumed rights and responsibilities in return relating to transmission ownership, maintenance and cost-recovery;
- TOs can plan supplemental transmission investments outside the RTEP process, for example to address local issues or as merchant investors. If the cost of these is to be recovered by transmission tariffs they must also be approved by FERC; and
- State PUCs approve siting and generally require that investments are in the interest of their state. The latter means that states have an interest in the above process, and in particular in cost-allocation rules.

2.2.1. *Planning principles*

PJM's RTEP process is designed to plan transmission investments and upgrades that will maintain grid reliability and improve economic efficiency:

- *Reliability*: The primary purpose of RTEP is to ensure reliability. The reliable supply of electricity involves two elements – adequacy and security. "Adequacy" relates to the production and delivery of electric power and energy in the quantity and quality that the customer requires. For example, sufficient power must be provided at acceptable voltage levels and frequency to match the customers' equipment specifications. "Security" relates to the ability to produce and deliver power whenever the customer needs it. Credible contingencies, such as the sudden outage of transmission facilities, should not result in uncontrollable power interruptions over a wide area.
- *Economic efficiency*: The RTEP process also includes the analysis of the economic efficiency of PJM's energy and capacity markets. Reliability-based RTEP projects are evaluated to determine if they can be brought-forward based on market efficiency benefits. Also, the review of historical and projected congestion metrics and other RTEP drivers may suggest new projects based on market efficiency as the primary driver. Transmission options that provide a mix of reliability and market efficiency improvements but which would be justified on neither criterion alone are also investigated.

The RTEP process is designed to systematically and objectively evaluate proposed transmission upgrades and generation connections, to make sure that compliance with reliability criteria is maintained. The process also includes a mechanism to mandate necessary grid investments.

The RTEP process is governed by Schedule 6 of the PJM Operating Agreement, which is the membership agreement for all market participants and is approved by FERC.[12]

The outcome of the annual RTEP process is a PJM Board-approved set of Baseline upgrades and Network upgrades, together with identification of direct connection requests from generator and merchant transmission developers, and a review of TO-planned Supplemental upgrades:

- *Baseline upgrades* are the key upgrades needed on the bulk power system for reliability and economic efficiency purposes.
- *Network upgrades* and *direct connection upgrades* are those upgrades necessary to connect new generators and merchant transmission facilities to the grid.[13] They are identified in individual System Impact Studies. The distinction between the two types of upgrades is the party responsible for the upgrade: The developer is solely responsible in the case of direct connection upgrades. In other cases a developer might not be responsible for 100% of the identified upgrade cost if other network users, for example other generation developers, also contribute to the need for the same network reinforcement.
- *Supplemental upgrades* are other upgrades planned by TOs to strengthen their local systems. These do not require PJM approval but like all transmission investments must be approved by FERC – and potentially by the state PUC(s) in the state(s) concerned. They are included as inputs to the RTEP process.

2.2.2. *Market-wide planning*

PJM's RTEP identifies transmission system additions and improvements to provide for the operational, economic and reliability requirements of PJM customers. The RTEP is a region-wide approach which integrates transmission with generation and demand response projects to meet expected load. The scope of the RTEP takes in the bulk power system facilities of TOs and all the transmission system facilities operated by PJM. The RTEP ignores internal TO zonal boundaries and state boundaries within the PJM footprint.

Within the RTEP process, studies are conducted that test the transmission system against mandatory national (NERC) standards and PJM regional standards. These studies look into the future to identify transmission overloads, voltage limitations and other reliability standards violations. Transmission upgrades to mitigate identified reliability criteria violations are then examined for their feasibility, impact and costs. PJM then develops transmission plans in collaboration with TOs to resolve violations.

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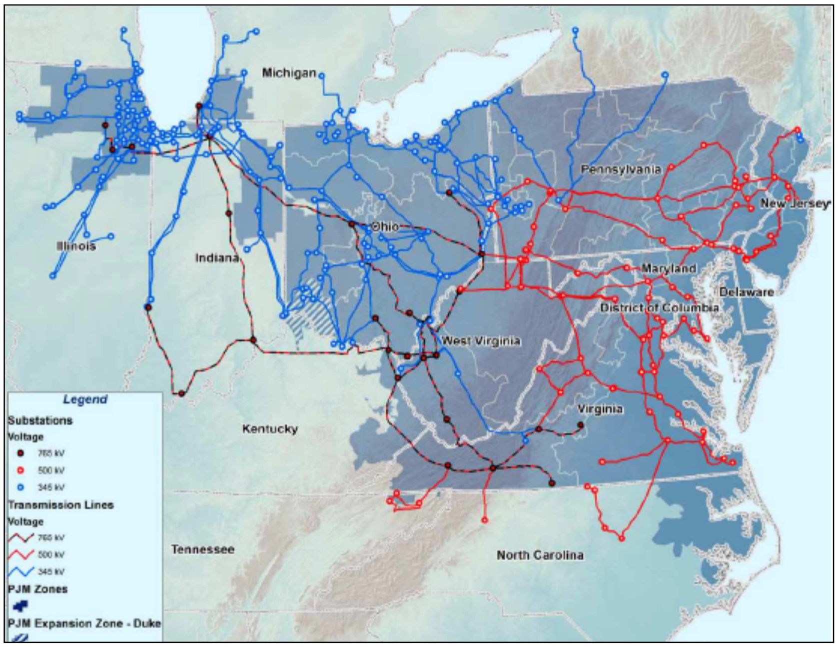
[12] Schedule 6 of the PJM Operating Agreement codifies the provisions under which PJM executes its RTEP process. The Transmission Planning Department of PJM's Planning Division publishes manuals describing the specific rules under which PJM undertakes the RTEP process. Refer to http://pjm.com/~/media/documents/manuals/m14b.ashx PJM's Open Access Transmission Tariff (OATT) describes the interconnection request process for generating resource interconnection, merchant transmission interconnection as well as specific process provisions to address long-term firm transmission service as well as Auction Revenue Rights.

[13] These upgrades can also result from requests for long-term firm transmission service, although in practice this is rare.

Figure 2.4 - PJM Backbone Transmission System



Source: PJM

The RTEP process includes the development of periodic Reliability Assessments to address specific system reliability issues in addition to the ongoing expansion planning process for the connection process of generation and merchant transmission.

The RTEP assesses both near-term (5-year) needs of the regional power grid as well as those over the long-term (15 years).

- Five-year- planning enables PJM to assess and recommend transmission upgrades to meet forecasted near-term load growth and to ensure the safe and reliable connection of new generation and merchant transmission projects seeking to integrate with the PJM grid. The results of these "baseline" studies identify needed transmission enhancements for anticipated system conditions and define cost allocation assignment. They also provide the starting point from which the need and responsibility for enhancements to accommodate connection requests is identified.
- Fifteen-year- planning enables PJM to assess longer-lead-time mitigation plans that often comprise larger magnitude transmission facilities that more efficiently address reliability issues. These facilities typically involve higher transmission level voltages – 500 kV and 765 kV – and can simultaneously address multiple NERC reliability criteria violations at all voltage levels. The 15-year planning horizon exceeds that required by NERC criteria. Essentially, the 15-year forward analysis provides a load-growth sensitivity analysis, capturing the equivalent of higher than forecasted load levels, often the result of unforeseen extreme weather conditions.

This approach enables PJM to address the cumulative effects of many system trends including long-term load growth, generation decommissioning, and broader generation development patterns.

Based on RTEP analyses, new transmission enhancements are recommended to PJM's independent Board of Managers (the PJM Board) periodically throughout the year to resolve identified reliability criteria violations and/or to achieve economic benefits. At the end of each planning year the process culminates in a single recommended plan – one RTEP – for the entire PJM footprint that is submitted to the PJM Board for consideration and approval.

The PJM Board has approved more than $1 billion of bulk power system transmission enhancements on average per year since the inception of PJM's RTEP process in 1997. Most of this amount is for transmission upgrades to the baseline transmission system. Approximately 18% is for additional bulk power system transmission upgrades to enable the connection of new generating resources and merchant transmission projects.

2.2.2.1. *Interregional considerations*

PJM participates in interregional planning activities with its neighbours and all other planning coordinators throughout the Eastern Interconnection according to interregional agreements. In particular, recent interregional planning efforts of PJM have focused on coordinated planning activities with the planning coordinators to the North, West and South of PJM, including NYISO, ISO-NE, Midwest ISO, TVA and the NC Collaborative. Figure 2.5 - Inter-regional coordination shows the location of these various regions.

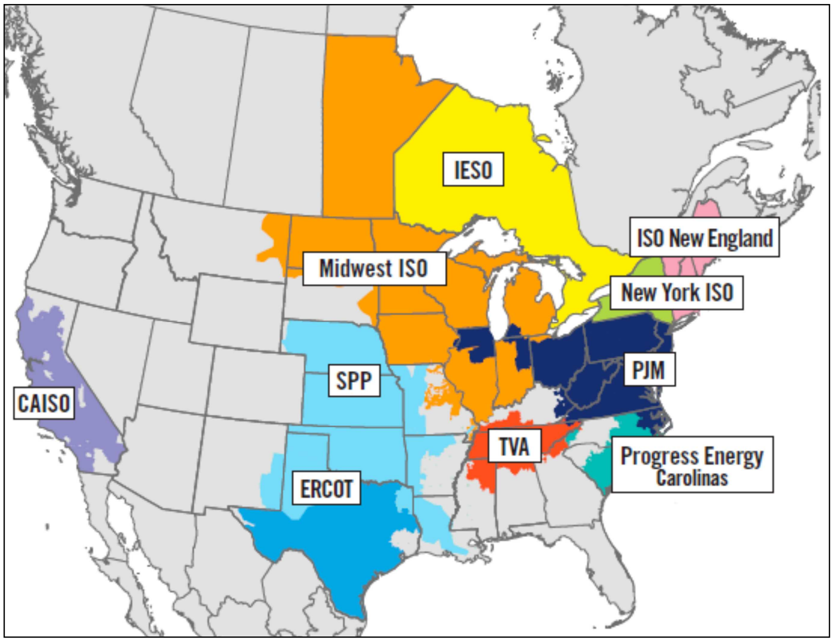
For example:

- PJM undertakes joint interregional analysis with NYISO and ISO-NE under the terms of the Northeast ISO/RTO Planning Coordination Protocol. Efforts include market efficiency model development, which has the ultimate goal of combining all three regions into one single-system model.
- Eastern Interconnection Planning Collaborative (EIPC) is a programme aimed at establishing greater interregional planning coordination across the entire eastern United States. The EIPC analyses a wide variety of future combinations of resources and policies, develops models, and provides advisory input to PJM and other RTOs/ISOs. It received funding from the Department of Energy to consider future resources and transmission options for the year 2030. It involves stakeholders from 40 states including state regulators. It has a Stakeholder Steering Committee composed of 29 delegates who participate in a collaborative decision-making process. This committee is supported by caucuses of additional representatives from all segments of the electric power industry: generators, transmission owners, marketers, alternative resource providers, municipal utilities, end user organizations, environmental organizations, RTOs/ISOs, and state regulators. The EIPC has three main working groups: 2020 Rollup; Modelling; and Scenario Planning.
- Individual studies on individual interfaces are also undertaken. A recent example is a PJM-MISO[14] Cross-Border Congested Flowgate Study that focused on common issues along the interface between the two systems near Lake Michigan. TVA and SPP also participated. The study identified transmission elements causing recent operational issues, based on stakeholder input and recent market congestion data. Potential transmission solutions were identified and evaluated. In this specific case, limited benefits to PJM were identified but study results were made available to stakeholders who can

[14] Midwest ISO, the RTO neighbouring PJM to the west.

individually choose to pursue participant-funded upgrades based on respective individual benefits. Refer to the case study of American Transmission Company set out in Box 2.1.

Figure 2.5 - Inter-regional coordination



Source: FERC

2.2.2.2. *Public Policy Drivers*

An increasing focus on climate change, energy independence and other policy areas by federal and state governments in recent years has had an impact on transmission system planning. The existence of violations of NERC Reliability Standards remains the primary basis for PJM's determination of need for new transmission facilities; however construction of transmission appears to be increasingly necessary to support the achievement of other public policy goals.

One element of these policies is greater use of renewable resources, primarily wind. The integration of wind resources, often distant from the population centres, has presented an on-going set of challenges to transmission planners. Likewise, the retirement of generating resources which are not able to meet environmental regulations (NOX, SOX, CO2 emissions and/or water quality).

The PJM Board has indicated it is concerned these factors have the potential to threaten reliability if not thoroughly analysed. Accordingly, recent additions to the RTEP process have required a range of sensitivity analyses to be performed. Further changes to the planning process are being examined to help manage the recent "whip-sawing" of transmission project in-service dates,[15] the result of periodic changes to modelling assumptions.

15 "Whip-sawing" refers to the phenomenon whereby the date of recommended construction of new transmission projects is highly sensitive to changes in modelling input assumptions. Many input assumptions are uncertain, for example the impact of demand response, the extent of economic retirement of older generators, and so on. Sensitivity analyses are helpful to evaluate the sensitivity of the timing of the need for new transmission to such factors.

Recent RTEP sensitivity analyses have incorporated such factors as the potential impact of state renewable portfolio standards, demand response/energy efficiency efforts, and “at-risk” generation (generators that may be economically forced to retire for environmental or other reasons). These sensitivity analyses have indicated in recent years that federal and state public policy initiatives have the real possibility of accelerating the occurrence of reliability criteria violations earlier – some many years earlier – than previously estimated.

2.2.3. *Localised planning*

While relatively minor compared to regional planning, localised transmission planning also occurs within the PJM service territory. This localised planning is undertaken by individual TOs and industry Interconnection Reliability Assessment Groups (IRAGs). The key purpose of localised planning is to support the regional RTEP planning process.

For example, a TO may develop a local transmission solution to a local issue. It can either forward the solution as a proposal for inclusion in the RTEP, or it can proceed with the project on its own account with state PUCs and FERC.

TOs are involved in the evaluation of direct connection requests. When PJM receives a request from a merchant generation or transmission developer for connection of new facilities, PJM assesses the impact of these requests on the transmission system of the TO concerned (as well as on the rest of the PJM system) and PJM also forwards the request to the TO so that the PJM study can be supplemented by studies conducted by TO transmission planners. The integration of new merchant projects into the TO’s transmission system is conducted based on the same planning principles as for any other transmission facilities. Localised planning criteria are designed to be compatible with NERC Reliability Standards (and NERC’s regional affiliates) and PJM Planning and Operating Manuals.

TOs also typically conduct their own regular planning process including seasonal assessments of system performance (up to 1 year); near-term facility addition studies (1-5 years); and long-term strategic planning (more than 5 years). The planning process typically begins with a deterministic appraisal of transmission system performance. When such appraisals identify potential problems, more detailed studies are conducted to evaluate the severity of the problem and to develop an optimal plan to remove or mitigate the deficiency.

Additional studies, limited to assessing regional and interregional transmission system performance, are conducted jointly with neighbouring utilities as part of PJM, NERC-affiliate and other IRAG agreements. These joint appraisals focus on measuring the strength of the interconnected network and on assuring coordination of facility planning and operational planning efforts. Where such assessments uncover deficiencies, the specific findings are referred to the appropriate company or companies to develop solutions as part of their normal planning processes.

The computer models used in localised transmission planning studies differ widely to suit the scope of each study. Power flow models are developed to represent system operation during highly stressed periods such as peak load conditions and heavy power transfers that simulate emergency and opportunity power transactions. System dynamics and short circuit computer models are also used, depending on the specific analysis, to complement the power flow models. Using these models, transmission system performance is assessed by simulating disturbances to identify system strengths and weaknesses.

2.3. Investment decision roles and responsibilities

The market-wide planning undertaken in the RTEP is considerably larger in scale than localised planning, and is the primary mechanism by which transmission investment in made in the region covered by PJM.

2.3.1. *Investment decision-making*

The RTEP process involves the following steps:

1. *Baseline reliability analysis*: This analysis uses annually updated load forecasts (prepared by PJM), committed resources, and firm transmission service requests to test the ability of the currently planned system[16] to satisfy all applicable planning standards (i.e. primarily NERC standards and PJM's own standards). This analysis identifies any required system reliability enhancements.[17] It also is the starting point for evaluating any proposed additions of new generation or merchant transmission projects.
2. *Identification of reliability upgrades*: The baseline analysis is extended to identify transmission solutions that resolve violations identified in Step 1. Note that PJM's remit is limited to transmission solutions – building a new generator in a congested location might improve the reliability of supply in that location but PJM is not tasked with generation investment planning (or investment in demand management resources).
3. *Market efficiency analysis*: A review of transmission congestion metrics and other cost measures may suggest new projects on market efficiency grounds (for example, if reduced congestion and losses cost are sufficiently high then a new project may be beneficial on efficiency grounds, even if it does not contribute material reliability benefits). Some projects may deliver a combination of reliability and efficiency benefits.
4. *Optimisation of upgrades*: A prioritisation list is formed if competing solutions can solve the same violations. The optimal mix of upgrades is found which addresses the violations, and as a secondary priority, improves market efficiency.[18]
5. *Evaluate compliance with NERC standards*: The RTEP, inclusive of the upgrades identified in the previous step, is re-evaluated for compliance with NERC standards. If it doesn't comply, the process returns to Step 1.
6. *Construct upgrades and allocate costs*: The TO undertakes the selected transmission investment(s) under instruction from PJM, obtaining necessary approvals from its state regulators and FERC, and coordinating with other stakeholders as necessary. Approved transmission costs are added to its rate base and collected via the transmission tariff charged by PJM (see section 2.4).

Any projects initiated outside the RTEP are fed into the RTEP process, either as candidate upgrades, local solutions, or independent projects (refer to case study in Box 2.1). The RTEP process accommodates not only expansion projects proposed by electric utility TOs, but also

16 The 'currently planned system' includes all existing generators, adjusted for certain proposed new entrants and certain proposed retirements. Likewise it includes the current transmission topology, adjusted for the existing (previous year's) RTEP. It includes PJM's forecast of demand – most importantly, of peak demand (net of expected demand response).

17 PJM uses results from a five-year power flow model to extrapolate results for the longer-term analysis (i.e. through year 15).

18 PJM's process of optimisation of alternative upgrade proposals is under continual review, in an effort to ensure the best mix of upgrades is always chosen.

merchant generation and transmission projects that are financed by private investors instead of utilities.

2.3.1.1. *Evaluation assessment and evaluation criteria*

The main tests applied in the baseline reliability analysis to evaluate compliance with standards and identify any violations are:

- An assessment of voltage violations; a load deliverability test; and a generation deliverability test.
- A thermal analysis is done to determine if line ratings are exceeded under normal, N-1 (contingency), and N-2 situations.19
- A voltage analysis is conducted using the same situations to evaluate voltage changes. A variety of transmission elements are held constant during this analysis so as to identify voltage drop violations and absolute voltage level violations.
- A load deliverability thermal analysis is conducted in which the goal is to have sufficient transfer capability to allow the delivery of adequate electricity to each load zone under extreme weather load conditions.
- A similar load deliverability voltage analysis is undertaken.
- A generation deliverability test is used to evaluate whether electricity can be delivered to defined areas under peak load conditions, and under the same N-1 and N-2 situations.
- A stability analysis is conducted for each individual generator every three years.20

2.3.1.2. *The market efficiency analysis*

The market efficiency analysis is performed after the completion of the reliability portion of the RTEP. Market efficiency analysis is a comparison of the cost of an upgrade to the projected economic benefit of the upgrade where the upgrade is identified as relieving a constraint or multiple constraints having an economic impact. Economic benefit is currently evaluated using a 70/30 rule and is calculated as: (0.7*change in production costs[21]) + (0.3*change in load energy payments). The benefit/cost ratio must be at least 1.25 over the first 15 years of the project.[22]

The goal of market efficiency analysis is as follows:

- Determine which reliability upgrades, if any, have an economic benefit if *brought forward*.
- Determine which reliability upgrades, if any, have an economic benefit if *modified* to relieve one or more economic constraints – in addition to providing the reliability benefits. For example the modification might be an expansion of the MW transfer

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19 Contingency analysis includes all PJM BES, all other facilities turned over to PJM by transmission owners, and critical facilities in systems adjoining PJM, including tie lines

20 Revenues from annual Financial Transmission Right (FTR) auctions are allocated annually to Firm Transmission Service customers through long-term Auction Revenue Rights (ARR) entitlements. PJM's RTEP process also incorporates steps to determine the transmission system enhancements required to maintain the 10-year feasibility of ARRs.

21 ie, reduced generator dispatch costs resulting from lower transmission losses and lower transmission congestion.

22 PJM Manual 14B.

capability of the upgrade. Such upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide additional economic benefits beyond resolving the reliability issues.

- Identify *new transmission upgrades* that may result in economic benefits. PJM's rules state that upgrades can be identified for transmission constraints that have an economic impact but for which no reliability-based need has yet been identified.

PJM's market efficiency analysis uses a market simulation tool which models hourly security-constrained generation commitment and dispatch over a defined series of future annual periods (e.g. 2013, 2016, 2019 and 2022). Economic benefits of transmission upgrades are determined by comparing results of simulations with and without defined transmission upgrades.

Prior to the initiation of each annual market efficiency analysis, the Transmission Expansion Advisory Committee (TEAC – refer to Section 2.3.1.3) reviews and the PJM Board approves key analysis parameters including fuel costs, emissions costs, future generation scenarios, load forecasts, demand resource projections, discount rates and annualisation factors.

PJM also evaluates market efficiency proposals submitted by stakeholders to address congestion in future years. PJM applies cost/benefit threshold tests to determine their possible inclusion in the RTEP. Proposals that meet or exceed a 1.25 benefit-to-cost ratio threshold test are further examined from a cost and reliability perspective prior to any RTEP recommendation to the PJM Board for approval.

2.3.1.3. *PJM decision-makers: committees and working groups*

The intention of the RTEP process is to ensure that all interested parties, including state regulatory agencies, TOs, merchant developers and other stakeholders, have an active role in planning for future electricity supply and reliability needs. A number of PJM committees and working groups provide the forums for their input:

- The activities of the Transmission Expansion Advisory Committee (TEAC)[23] provide the primary stakeholder forum for the ongoing exchange of ideas, discussion of issues and presentation of RTEP upgrades. The responsibilities of the TEAC include the provision of:
  - Comments and recommendations on the scope and assumptions for RTEP studies, including economic/market efficiency analysis;
  - Comments on the RTEP analysis at defined points throughout the RTEP process cycle;
  - Comments and recommendations on the RTEP that will be proposed to the PJM Board for consideration and approval, as necessary; and
  - Comments and recommendations on RTEP matters as requested by the PJM Board.

[23] TEAC membership and participation are open to parties as described in the PJM OA Schedule 6, Section 1.3(b): "…(i) all Transmission Customers, as that term is defined in the PJM Tariff, and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the agencies and offices of consumer advocates of the States in the PJM Region exercising regulatory authority over the rates, terms or conditions of electric service or the planning, siting, construction or operation of electric facilities and (v) any other interested entities or persons."

- The PJM Planning Committee (PC) is established under the PJM Operating Agreement and has the responsibility to review and recommend system planning strategies and policies as well as planning and engineering designs for the PJM bulk power supply system to assure the continued ability of the member companies to operate reliably and economically in a competitive market environment. Additionally, the PC makes recommendations regarding generating capacity reserve requirement and demand-side valuation factors.
- PJM's Regional Planning Process Working Group (RPPWG) enables a stakeholder process to evaluate and make recommendations to the PJM Members Committee to reform the present connection queue and study processes. The RPPWG addresses specific issues associated with 15-year planning, market efficiency and interconnection request processes.
- The Sub Regional RTEP Committees (SRRTEP) provide a forum to review Subregional RTEP upgrades and to provide input and recommendations to the TEAC:
  - Mid-Atlantic SRRTEP
  - Southern SRRTEP
  - Western SRRTEP

2.3.1.4. *Input data assumptions*

Inputs to the RTEP process are vetted by the TEAC. Key inputs used to develop the power flow cases include the PJM Load Forecast, topology changes from the previous year's RTEP and updated interchange information, and updated generation information. Fuel price forecasts are required for the market efficiency analysis.

- The PJM Load Forecast Report is used for modelling loads, and unrestricted peak loads are adjusted to account for changes in Demand Side Response (DSR), which in PJM is comprised of Energy Efficiency (EE) and load management (LM) resources. (Section 2.3.1.5 describes more on PJM's demand forecasting process.)
- Transmission upgrades approved by the PJM Board along with merchant transmission projects expected to be in service are included in the analysis. Power flow cases also include upgrades to connect new generation for which System Impact Studies have been completed.
- Each annual RTEP baseline model includes new generators that have executed an Interconnection Service Agreement (ISA) or signed a Facilities Study Agreement (FSA) since the previous year's RTEP.[24] Generators with announced intentions to deactivate or

[24] PJM includes generators with executed FSAs in its power flow base case model in order to allow the generators to contribute to generator deliverability problems. However, PJM does not include a generator that only has an executed FSA – i.e., one that has not yet executed an ISA – to relieve system problems, for example in an area experiencing a capacity emergency in the load deliverability test. This approach ensures that the transmission system will be reliable whether or not the generator ultimately completes the connection process and goes into commercial operation. PJM uses this approach for a connection request that has not executed an ISA because of the remaining uncertainty as to whether that generator will ultimately go into service. PJM uses the execution of the ISA as the indicator that a project can reasonably be expected to be placed into service and, therefore, be available to contribute to the resolution of violations of NERC Reliability Standards. Consequently, PJM has determined that those generators with an executed ISA should be modelled in all subsequent baseline analyses the same way an existing generation capacity resource is modelled, i.e., the generator is included in the baseline and is allowed to contribute to system problems and to relieve system problems.

suspend interconnection process activity are removed. The generation data is also updated each year to include up-to-date reactive capability information.[25]

- The RTEP uses a commercially available simulation tool and database which includes fuel price forecasts for each fuel type. Forecasts for short-term gas and oil prices are derived from NYMEX futures prices.
- Assumptions regarding longer-term generation capacity additions are also required by the market efficiency analysis. New generation needed to maintain PJM's reserve margin in future study years is added to the model according to the location and fuel type of generation connection requests in recent PJM queues. Assumptions regarding emissions allowance prices are obtained from a national industry working group on that subject.

2.3.1.5. *Demand forecasts*

The PJM Load Forecast Report is developed by PJM staff. The load forecast model used for this report incorporates the three classes of variables:

- Economic conditions;
- Calendar effects such as day of the week, month and holidays; and
- Weather conditions across the RTO.

Economic conditions are the key drivers of year-on-year growth and are based on a composite variable that incorporates six economic measures (Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment). This composite variable provides for localized treatment of economic effects.[26]

PJM's load forecast model produces a 15-year forecast assuming normal weather for each PJM zone, region, locational deliverability area, and the total RTO. The forecast is of peak loads and net energy, and is adjusted for load management and energy efficiency programmes.

2.3.2. *Detailed design, procurement and construction*

Once PJM has identified that an investment is needed, it is allocated to a TO based on service territory. Under PJM agreements, TOs are obligated to build transmission projects that are needed to maintain reliability standards and that are approved by the board of PJM under the RTEP process.

The RTEP process determines the need for and benefits of a transmission project; it does not review or approve a transmission line's siting. That is the responsibility of the affected state regulators, including state PUCs.

TOs undertake the detailed design of transmission assets and their configurations. They obtain planning permission/consents, and wayleaves/easements within their states as required. TOs manage procurement of the transmission upgrades, which may be through competitive

[25] PJM has a capacity market in which each Load Serving Entity (LSE) within PJM must own or acquire capacity resources to meet its respective capacity obligation. Data from the outcomes of this market are also used as inputs to the RTEP process.

[26] Prior to the 2012 Load Forecast Report, a single economic driver variable was used - Gross Metropolitan Product.

tender to third-party construction companies. The TOs ultimately own the transmission assets.

Independent developers, where applicable, must adhere to applicable TO technical requirements and standards. These include engineering design requirements and standards; equipment specification and suppliers; construction requirements and standards; and, engineering, procurement and construction process requirements and standards.

2.4. Economic regulation arrangements

The costs of transmission upgrades, as well as the costs of the pre-existing transmission system, are recovered through transmission tariffs. In summary:

- PJM collects transmission tariff revenues from transmission customers, using transmission tariffs approved by FERC, and passes the proceeds to the appropriate TOs.
- A separate transmission tariff is determined for each TO territory (i.e., zone).
- Transmission customers pay for transmission service based on the zone in which their loads are located. Transmission customers include Load-Serving Entities, within a zone, as well as entities who export energy to consumers outside PJM (in which case the transmission tariff of the applicable PJM-border zone is used).

2.4.1. *Transmission upgrades: Tariffs paid by transmission customers*

PJM is responsible for allocation of transmission upgrade costs to zones (or in some cases specific PJM members) in accordance with provisions contained in PJM's Operating Agreement and Open Access Transmission Tariff (OATT). PJM calculates the cost allocation of all RTEP upgrades according to these provisions and then submits them to the PJM Board for approval. The method of allocation depends on the type of facility:

1. High voltage facilities;
2. Other reliability upgrades;
3. Market efficiency upgrades; and
4. Direct connections.

2.4.1.1. *High voltage facilities*

Transmission lines rated at 500 kV and above (both reliability and economic upgrades) are considered *regional facilities* and their costs are currently recovered from loads through "postage-stamp" tariffs – meaning that costs are allocated across PJM based on each PJM zone's share of non-coincident peak load. Lower-voltage facilities that are a part of the relevant transmission project and needed to directly support integration of the high-voltage lines are also designated as regional facilities and their costs are treated in the same way.

The use of postage stamp rates in this way has been controversial, has been legally challenged in PJM by stakeholders, and is subject to on-going regulatory review at FERC.

2.4.1.2. *Cost allocation for other reliability upgrades*

The allocation of cost for other baseline upgrades built for reliability purposes falls into two categories:

1. Upgrades costing less than US$5m for facilities less than 500 kV are allocated to load in the zone in which the upgrade occurs; and

2. The cost of other reliability upgrades less than 500 kV is allocated to load by zone on a beneficiary-pays approach. The determination of benefit is based on elimination of a reliability criteria violation. The parties causing the violation (typically loads) are deemed the parties that benefit from elimination of the violation and the quantification of the benefit is based on the relative contribution to the violation being eliminated. Accordingly, each cost allocation calculation is based on the particular assumptions used to determine whether or not a violation exists of a particular criterion.

Under Category 2, to the extent a criteria violation is based on the thermal limits of a transmission facility, the cost responsibility is allocated on the basis of the relative contribution of the load in each zone to the flow on that facility. The contribution is calculated on an incremental basis, using a "distribution factor" approach. Thus, it is possible that the costs of upgrades required to mitigate violations in one zone may be allocated in significant part to load in other zones. The cost is applied to the transmission tariff, which is zone-specific and paid by loads.

For criteria violations based on voltage criteria, thermal surrogates are determined, such that the flow on a transmission facility or group of facilities best correlates to the reactive performance of the system at the point of the criteria violation.[27]

2.4.1.3. *Market efficiency cost allocation*

Market efficiency upgrades less than 500 kV can fall in one of three categories:

1. *Upgrades that are enhancements to reliability-based projects* (for example, building additional capacity over and above that required to solve criteria violations, so as to reduce the cost of serving load): these costs are allocated the same way as reliability upgrades.

2. *Upgrades that accelerate completion of an approved reliability project*: Costs are allocated to load zones based on the forecast reduction in "load energy payments"[28] on a pro-rata basis[29] if there is at least a 10% difference in the amount allocated to any zone using this method and the method for reliability projects. This methodology applies for the initial tariff years for which the project is accelerated, and then the tariff reverts to the method for reliability upgrades for subsequent years.

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[27] A special agreement pertains to reliability upgrades that span the PJM-MISO border. Allocation between RTOs is based on each RTO's contribution to the constraint that required the need for the upgrade. Allocation within each RTO is then applied according to the RTO's respective methodology.

[28] The calculation of *load energy payment* for a zone assumes that all energy forecast to be consumed in the zone is purchased at the Locational Marginal Prices (LMPs) in that zone, for each year of the study period.

[29] Only for zones that show a *decrease* in the load energy payments.

3. *Market efficiency upgrades for which no reliability-based need has been identified*: Costs are allocated on a pro-rata basis to zones that have a forecast decrease in load energy payments.

The cost allocation methodology for market efficiency investments has been the subject of dispute. As of the date of this report, the methodology continues to be a subject of ongoing discussion between stakeholders, and at FERC. However, in practice, relatively few projects fall into the market efficiency category.

2.4.1.4. *Direct connections*

Upgrades necessary to connect new generators and merchant transmission facilities to the grid are borne in full by the project proponents (i.e. by the specific PJM members concerned).

2.4.2. *Tariffs received by TOs*

The revenue collected by PJM from transmission tariffs each year is pre-determined so as to match the *revenue requirements* of the TOs. The revenue requirement is determined through a regulatory process: the capital cost of transmission assets of each TO (including the cost of any approved upgrades) are recorded in a regulatory asset base, and the allowable costs that can be recovered each year contribute to the TO's annual transmission revenue requirement. The revenue requirement, which must be approved by FERC, provides for a "return of" capital (depreciation), a "return on" capital (at an approved rate of return/ cost of capital) and operating costs. The TO is required to maintain regulatory accounts showing the balance of costs incurred and costs recovered. Each year PJM collects the transmission tariff revenue from transmission customers and forwards each TO an amount equal to its revenue requirement.[30]

Rate cases are periodic – transmission tariffs are reset at each rate case and are generally indexed between cases except when specific major new investments are added.

2.5. Reliability standards

The key reliability standards used by PJM in the RTEP are set by NERC. A summary of NERC's transmission planning reliability standards[31] are set out in Appendix 2.[32]

NERC works with a large number of stakeholders to develop standards and adapt them on a continual basis. NERC's members come from all segments of the electric industry, including investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. These entities account for virtually all the electricity supplied in the United States, Canada and a portion of Mexico.

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[30] Subject to annual true-ups and other adjustments.

[31] The full list of *categories* of NERC reliability standards is as follows: Resource and demand balancing; Communications; Critical infrastructure protection; Emergency preparedness and operations; Facilities design, connections, and maintenance; Interchange scheduling and coordination; Interconnection reliability operations and coordination; Modelling, data, and analysis; Nuclear; Personnel performance, training, and qualifications; Protection and control; Transmission operations; *Transmission planning*; and Voltage and reactive.

[32] Refer to the following link for the complete set of NERC standards: http://www.nerc.com/docs/standards/rs/Reliability_Standards_Complete_Set.pdf

In developing reliability standards, NERC's process involves having registered members of twelve industry sectors vote to approve or reject proposed new standards. The sectors are:

1. Investor-owned utility;
2. State or municipal utility;
3. Cooperative utility,
4. Federal or provincial utility or power-marketing administrator;
5. Transmission-dependent utility;
6. Merchant electricity generator;
7. Electricity marketer;
8. Large end-use electricity customer;
9. Small end-use electricity customer;
10. Independent system operator or regional transmission organization;
11. Regional reliability organization[33]; and
12. Government representative.

A Registered Ballot Body (RBB) is a group of members that qualify for voting on proposed standards. Any member who is directly and materially affected may propose a new standard or a revision to an existing one. Any member may submit comments on a standard under development. Each proposed standard or project has its own ballot pool. RBB membership does not automatically enlist members in every ballot pool, so members must continually review upcoming projects of interest and join each ballot pool in which they want to vote. Members are able to vote online.

NERC has delegated some authority for the purpose of proposing and enforcing reliability standards by entering into delegation agreements with the regional entities ReliabilityFirst Corporation and the Southeastern Electric Reliability Council (SERC).[34]

PJM and individual TOs also have their own reliability standards. PJM's are applied in the RTEP process and individual TO standards are applied for localised planning. These standards are generally of a second-order magnitude of significance, compared to the NERC standards.

[33] Such as SERC and ReliabilityFirst Corporation.

[34] Region-specific reliability standards can also exist. Regional reliability standards are intended to provide for as much uniformity as possible relative to NERC reliability standards across the interconnected bulk-power system of the North American continent. A regional reliability standard is expected to be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or to be a regional difference necessitated by a physical difference in the bulk-power system.

2.6. Recent developments

A key development currently underway in PJM is work aimed at potentially modifying and improving the mechanism of cost allocation of transmission upgrades, including the mechanism of postage stamp rates described in Sections 2.4.1.1 and 2.4.1.3.

A general issue that has been developing over recent years is that PJM's planning responsibilities have become increasingly complicated with higher levels of renewable resources, demand management, and energy efficiency resources entering the PJM system, at the same time that load growth rates have fallen (as a result of an economic slow-down) and new regulatory-imposed mandates have been introduced. In addition, environmental factors are impacting the viability of some coal-fired stations and increasing the risk that PJM must make expensive "reliability must-run" arrangements with these stations to preserve local reliability of supply. These influences, together with the implications of a proliferation of other public policy objectives have led to increased use of sensitivity analyses within the RTEP and investigation of other changes to the planning process that may be required. This is an on-going process.

The methodology of optimising the choice of upgrades (refer to Step 4 of the RTEP process described in Section 2.3.1) is subject to-going improvement.

On-going improvements to interregional coordination are also underway, as described in Section 2.2.2.1.

Box 2.1
Case study: localised investment decision-making in PJM

A recent (2011-2012) example of localised investment decision-making is the proposed transmission line to be constructed from Pleasant Prairie in Southeast Wisconsin (in MISO) to Zion Energy Center in Northeast Illinois (in PJM) by the American Transmission Company (ATC).

This proposed line was planned by ATC on a localised basis – i.e. outside the PJM or MISO regional transmission planning processes, which tend to focus on within-RTO investment. Network simulation analysis of the Midwest and North-eastern United States (taking in both MISO and PJM) suggests the line is highly beneficial relative to its cost. By reducing or eliminating congestion on a constrained interface between Wisconsin and Illinois it will allow a significantly increased volume of cheap coal-fired power to flow south and east into Illinois.

ATC's principal business activity is transmission, and it is a FERC-regulated company earning a regulated return on its rate-base of transmission assets. As such it is not incentivised to construct the line on the basis of the economic value of transferring additional power from Wisconsin to Illinois. The Wisconsin retail market, however, is highly regulated and vertically-integrated companies act as both generators and retailers in Wisconsin. These regulated utilities are required to pass through any benefits of off-system sales to their retail customers. The ATC line allows additional profitable off-system sales by Wisconsin utilities and therefore benefits Wisconsin consumers. On this basis the addition of the line is attractive to the Wisconsin PUC, who must approve the Wisconsin portion of the line, and who represents the interests of Wisconsin consumers. Wisconsin consumers are a major beneficiary of the line and it is their economic interest which has driven the investment decision.

The line is also attractive to the Illinois PUC who must show under state law that new transmission "promotes the development of an effectively competitive electricity market that operates efficiently…[and]…is equitable to all Illinois customers…". The new line allows greater volumes of out-of-state capacity to compete to serve load in Illinois (i.e. it aids competition) and it allows lower-cost energy to flow into Illinois which is expected to lower the market price to consumers.

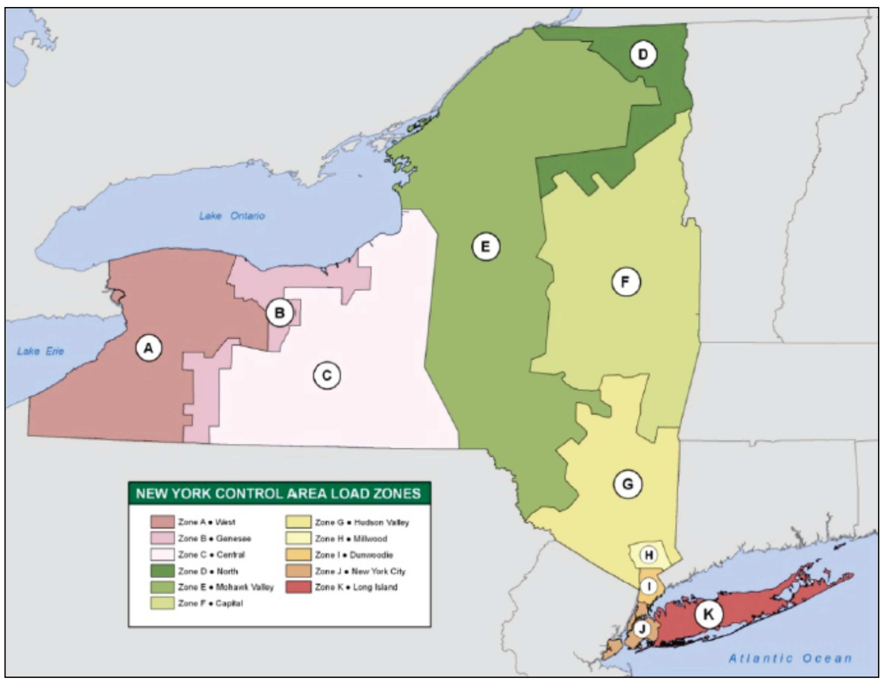
MISO and PJM were notified of the line, it appears in their respective transmission schedules, and it is likely the line improved reliability and/or reduced cost in these RTOs, but it wasn't either RTO that conducted the investment decision-making leading to this investment. The ATC line is perhaps an illustration of how the investment decision-making process can differ at the edge of an RTO, compared to within an RTO, and how retail regulation at the state level can influence the decision-making process.

3. New York

Compared to PJM, New York's economic planning and cost allocation mechanisms are generally less extensive and less developed, and investment in transmission in New York in recent years has been at a lower rate. New York uses a more market-based approach to transmission planning than PJM, nevertheless there are provisions for regulated backstop projects to meet reliability needs in the event market-based solutions are inadequate. Transmission planning in New York centres on a Comprehensive System Planning Process (CSPP), which is led by the New York Independent System Operator (NYISO), the ISO[35] for the state of New York.

The territory of NYISO covers the state of New York.

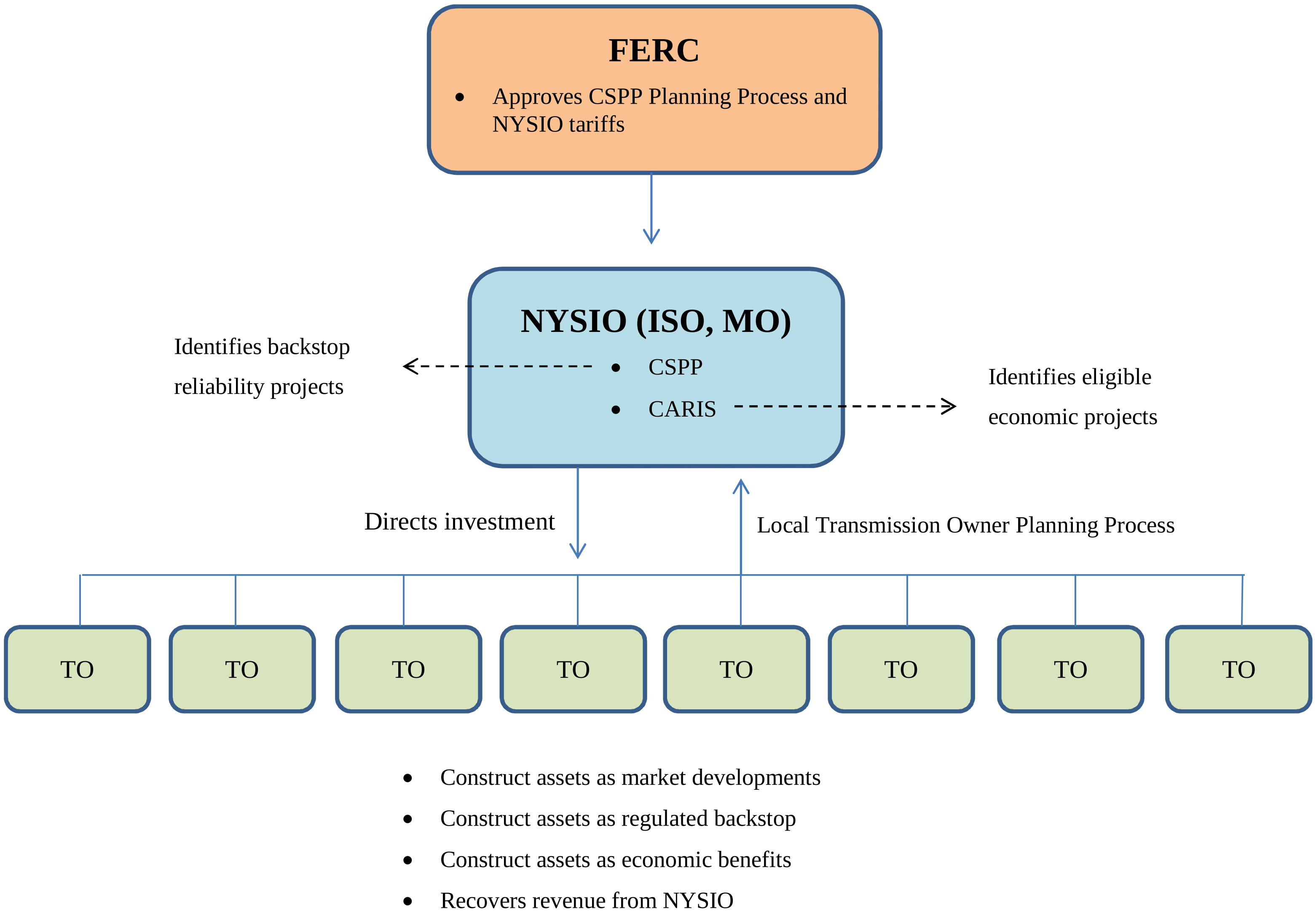
Figure 3.1 - New York Control Area



Source: New York State Energy Plan www.nysenergyplan.com

[35] ISO and RTO are FERC-defined terms, and in practice there is very little difference between the legal definitions of each.

Figure 3.2 - Summary of Key Roles and Responsibilities - New York



3.1. Institutional arrangements

The key institutions and entities within the New York market relevant to transmission planning are as follows:

- New York Independent System Operator (NYISO);
- TOs and merchant transmission investors;
- NERC, together with its regional affiliate which in the case of New York is the Northeast Power Coordinating Council (NPCC);
- The New York State Reliability Council (NYSRC);
- FERC; and
- The New York State Public Service Commission, which is the state PUC of New York.
- Other stakeholders include generating companies, Load-Serving Entities, land-owners, and others.

The following is a description of the roles of the key institutions and their relationship to each other.

3.1.1. *NYISO*

New York Independent System Operator, Inc. (NYISO) is the ISO for the state of New York. NYISO is both system operator and market operator. It is an independent, not-for-profit corporation established to ensure continued reliable operation of New York State's bulk power transmission facilities. NYISO's stated mission is to:

- Provide reliable operation of New York's bulk electricity grid;
- Administer open and competitive wholesale electricity markets in New York;
- Prepare for New York's energy future; and
- Advance the technological infrastructure of the electric system.

A central principle of NYISO is to provide accurate, open and transparent planning information to allow market participants to determine what resources are developed and built. NYISO does not build or own transmission itself. NYISO conducts various planning studies in coordination with the eight transmission owners in New York State (ie, six investor-owned utilities and two public authorities: refer to the list of these entities in Section 3.1.2).

NYISO is governed by a 10-member Board of Directors, which includes the NYISO President & CEO. The Board is comprised of members with backgrounds in the electric power industry, finance, academics, technology, communications, and the law. The Board is required to be independent. Its members have no business, financial, operating or other direct relationship to any Market Participant or stakeholder.

NYISO staff report to the CEO who in turn reports to the Board.

In parallel there are two stakeholder committees – the Operating Committee[36] and the Business Issues Committee[37] – which contain representation from: TOs; generation owners; other suppliers; end-use consumers; and public power and environmental parties. These committees report to a Management Committee, which in turn reports to the Board.

3.1.2. *Transmission Owners (TO)*

TOs in New York have a similar role to those in PJM, with the key difference that the New York regional transmission planning process starts with a "bottom-up" plan developed by each TO, as opposed to the "top-down" approach in PJM. The eight existing TOs in New York are:

1. Central Hudson Gas & Electric Corporation;
2. Consolidated Edison;
3. Orange & Rockland (part of ConEd);
4. Long Island Power Authority (LIPA);
5. National Grid;
6. NYSEG (Iberdrola USA);
7. Rochester Gas & Electric; and
8. New York Power Authority (NYPA).

Merchant transmission investors may also enter the New York market.

3.1.3. *NERC*

NERC's role in New York is the same as that in PJM. The regional entity to which NERC has delegated authority is the Northeast Power Coordinating Council (NPCC[38]). The geographical scope of NPCC covers New York, New England, and much of eastern Canada (refer to Figure 2.3 – North American Regional Reliability Councils and Interconnections).

3.1.4. *New York State Reliability Council (NYSRC)*

The NYSRC is, in effect, a third-level reliability organisation (NERC and NPCC being the other two) whose scope is limited specifically to New York State. NYSRC is a not-for-profit entity whose mission is "to promote and preserve the reliability of electric service on the New York State Power System by developing, maintaining, and, from time-to-time, updating the Reliability Rules which shall be complied with by NYISO and all entities engaging in electric transmission, ancillary services, energy and power transactions on the New York State Power System". NYSRC reliability rules may be more specific or stringent than NERC standards and NPCC criteria. In practice the standards and criteria of all three organisations must be met.

[36] The Operating Committee coordinates operations, develops procedures, evaluates proposed system expansions and acts as a liaison to the NYSRC.
[37] The Business Issues Committee establishes rules related to business issues and provides a forum for discussion of those rules and issues.
[38] Refer to www.npcc.org

NYSRC is required to carry out its mission with no intent to advantage or disadvantage any market participant's commercial interests. NYSRC's monitors compliance with the Reliability Rules by working in consultation with NYISO.

NYSRC is governed by an Executive Committee comprised of thirteen members consisting of representatives from to TOs and power authorities, one representative of IPPs, one representative of large consumers, one representative of municipalities and cooperatives, and four members not affiliated with any market participants.

3.1.5. *FERC*

FERC’s role in New York is very similar to that in PJM. From time to time however, issues of jurisdiction arise between FERC and the New York State PSC and other state agencies because FERC’s key responsibility (as a federal agency) is in matters of *interstate* commerce. Since the New York market covers a single state, instances can arise in which FERC’s regulatory jurisdiction is challenged. As a practical matter FERC is nevertheless the key regulator of transmission issues in New York.

3.1.6. *New York State Public Service Commission*

The New York State Public Service Commission (New York State PSC) is the state PUC in New York and tends to have a larger role in transmission matters than in many states because the relevant market is entirely within state borders.

3.2. Planning process

New York’s CSPP is a unique process that is significantly different from the planning processes of other US markets. In particular New York’s CSPP is, in practice, primarily a market-based approach for transmission planning, with provisions for ‘regulated backstop projects’ to meet reliability needs in the event market-based solutions are inadequate.

New York’s philosophy of achieving market-based solutions whenever possible is reflected in its commitment to location pricing signals under the Locational Marginal Pricing (LMP) system of nodal prices, which sends strong signals to market participants regarding the efficient location of generation and transmission investment.

Key features of the CSPP are as follows:

- The CSPP process is undertaken every two years and is initiated by individual TOs, who start by developing comprehensive plans for their individual service territories. Using these plans as inputs, NYISO then sequentially conducts a reliability study and then a market efficiency (‘economic’) study.
- Each of the planning studies is conducted subject to the requirements of FERC-approved processes and is governed by the reliability rules established by the NERC, NPCC, and NYSRC;
- The roles of FERC and NERC are essentially the same as in other RTOs/ISOs;
- The role of NYISO however, tends to be less prescriptive than in other RTOs/ISOs. While the NYISO coordinates and conducts its system transmission studies, it relies primarily on market forces to determine which projects go ahead. NYISO evaluates and

monitors the reliability of the system and any prospective changes to it. In most cases NYISO does not expressly direct or determine upgrades, but it will if required.

- The New York State PSC reviews any regulated backstop projects proposed by TOs or other developers upon request. Specifically it:
  - Reviews and screens “gap” solutions;
  - Adjudicates disputes relating to reliability determinations in the assessments described below, if solely within its jurisdiction;[39]
  - Selects preferred regulated solutions;
  - Generally has final siting & certification authority with respect to backstop solutions; and
  - PSC staff participate in the NYISO process and facilitate necessary approvals to ensure reliability.

In practice relatively little transmission has been built to date under the CSPP in New York, compared to the RTEP in PJM.

3.2.1. *Planning principles*

New York’s CSPP process is designed to be a comprehensive process for reliability planning which takes into account all potential system resources available – including generation and demand response, in addition to transmission – and which develops progressively off TO plans, to include market-wide reliability plans and finally market-wide economic planning.

The CSPP was developed through NYISO’s stakeholder governance process with the Electric System Planning Working Group (ESPWG) of New York stakeholders, working together with NYISO staff. The CSPP evolved from earlier planning processes used by NYISO, in response to a FERC initiative.[40]

3.2.2. *Localised planning*

The CSPP begins with the Local Transmission Owner Planning Process (LTPP) in which each TO develops a transmission upgrade plan based on the reliability needs of its specific service territory. The TOs plan for their local systems, using applicable criteria of NERC, NPCC, and NYSRC. The LTPP allows stakeholders to provide input and examine each TO plan individually. Stakeholders can use the TO websites to review and comment on the needs addressed, the planning criteria, data, models, methodologies, and assumptions used by each TO.

NYISO holds one or more stakeholder meetings of the ESPWG and the Transmission Planning Advisory Subcommittee during each two-year CSPP cycle, at which each TO’s current Local Transmission Plan is discussed.

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39 FERC adjudicates disputes solely within FERC’s jurisdiction. Other rules provide for a joint process on issues of dual jurisdiction.

40 Specifically, FERC Order No. 890, FERC’s Final Rule on Open Access Reform

3.2.3. *Market-wide planning*

The main market-wide planning activity in New York is the CRPP. NYISO uses the CRPP to identify reliability needs and administer a process whereby solutions are proposed, evaluated and implemented in order to maintain the reliability of the bulk power system. The CRPP is followed by an economic analysis, the Congestion Analysis and Resource Integration Studies (CARIS). Both of these processes are discussed in detail in the following section.

3.3. Investment decision roles and responsibilities

The market-wide CSPP process undertaken by NYSIO is the primary mechanism by which transmission investment decisions (outside of market-driven investments) are made in the New York market.

3.3.1. *Investment decision making*

This section describes the three components of the CSPP in detail. The three components are:

1. *Local Transmission Owner Planning Process (LTPP)*: This is a local transmission planning process undertaken by TOs.
2. *Comprehensive Reliability Planning Process (CRPP)*: This is a reliability planning process undertaken by NYISO and in turn consists of two sub-components:
    a. *Reliability Needs Assessment*;
    b. Comprehensive Reliability Plan;
3. *Congestion Analysis and Resource Integration Studies (CARIS)*: This is an economic planning process undertaken by NYISO and is a recent introduction to the CSPP.

3.3.1.1. *Local Transmission Owner Planning Process*

Local transmission plans have the goal of reliably serving local forecast loads within each TO over a ten-year planning horizon, given conservative assumptions regarding the connection of new generating projects.

Local planning criteria can vary from TO to TO, however each is designed to be compliant with NERC standards, NPCC criteria, NYSRC rules and NYISO procedures. By way of illustration, the transmission planning criteria of Consolidated Edison (ConEd[41]) fall under the following headings:

- Fundamental Design Principles
- Performance Criteria
- Voltage Assessment
- Thermal Assessment

[41] ConEd is the TO for New York City. The source of information on ConEd's planning process is the following website: http://www.coned.com/tp/transmission_planning_process.asp

- Stability Assessment
- Subtransient Conditions Assessment
- Short Circuit Assessment
- Extreme Contingency Assessment
- Underfrequency Load Shedding
- System Restoration

ConEd considers three elements in its transmission plan:

1. A Transmission Load Area (TLA) assessment (TLAs are sub-zones of the TO's system);
2. Transmission substation assessment; and
3. An assessment of connection of new generators.

*TLA*s: Planning generally includes the detailed evaluation of TLAs over the ten-year period. There are a number of possible actions that can address TLA reliability criteria deficiencies, for example:

- Additional transmission expansion into the TLA, which may require other transmission support farther out from the TLA;
- Demand side management programs targeting load within the TLA;
- Increasing the capacity of existing transmission components;
- Transferring load from one TLA to another by transferring a portion of one network within the load area to a network in another load area that has spare capacity;
- New generation within the TLA; and
- Combinations of the above.

ConEd performs analysis on a case-by-case basis to determine the most cost-effective remedial action for any reliability criteria violations identified.

ConEd's *transmission substation assessment* investigates whether new substations are required to serve load growth in a TLA, either at the 138 kV level or the 345 kV level.

Finally, ConEd's *assessment of connection of new generators* evaluates whether reliability criteria can be met in some cases by the interconnection of new generation resources within the system or by connections to new or existing generation resources outside the system.

3.3.1.2. *Comprehensive Reliability Planning Process*

The CRPP is a ten-year study of resource adequacy and transmission reliability, with the main difference relative to the local transmission planning process being that it considers the entire New York bulk power transmission system, and not one TO's zone at a time. The CRPP is conducted after the local transmission planning process and, like the local planning, also considers generation and demand response options in addition to transmission solutions. The CRPP consists of two steps: a Reliability Needs Assessment (RNA), followed by the development of a Comprehensive Reliability Plan (CRP).

The RNA is conducted as follows:

- NYISO evaluates the system-wide adequacy and security of the bulk power system over the next ten years. The input data for this evaluation is the output of the local transmission plan for each TO.
- NYISO identifies the MW quantity of resources needed to satisfy reliability criteria, and the general locations where those resources are needed.
- NYISO then designates one or more relevant TOs to prepare a proposal and, if required, be responsible for developing regulated backstop solutions to address designated reliability needs.
- NYISO also makes a request for market-based and alternative regulated solutions that may be submitted by any qualified developer. The solutions do not have to be in the specific MW quantities or locations as identified above, since there are various combinations of resources and transmission upgrades that could meet reliability needs that have been identified.

Following its analysis of all proposed solutions, NYISO determines whether there are sufficient market-based solutions to meet the reliability needs identified. If reliability issues remain following the incorporation of the market-based solutions, then NYISO directs the responsible TOs to initiate regulated backstop solutions, as required, to fully meet reliability needs. NYSIO directs TOs to undertake identified investments based on geographic area.

NYISO then develops the CRP resulting from the above process. The CRP is NYISO's overall plan for meeting the reliability needs of the New York grid. It is approved by the NYISO Board of Directors following an extensive stakeholder review.

3.3.1.3. *Congestion Analysis and Resource Integration Studies*

The CARIS process is an economic analysis conducted by the NYISO every two years, with a ten-year look-ahead. It uses the CRP as input. The CRP provides a reliable system though the ten-year planning horizon of the CARIS process.

Like the CRP, the CARIS process considers all resources (generation, transmission, demand response) on an equal basis. The purposes of the CARIS process are as follows:

- To provide estimates of future congestion on the NYS bulk transmission facilities for a ten year horizon;
- To identify, through appropriate scenarios, factors that might mitigate or increase congestion;
- To provide information on generic solutions to reduce congestion;
- To provide opportunities for developers to propose solutions that may reduce congestion; and
- To provide a process for the evaluation and approval of regulated economic transmission projects for regulated cost recovery.

CARIS consists of two phases: a study phase; and a project evaluation phase.

In the *study phase* a congestion assessment is performed to identify the three congestion elements or paths of the grid which would have the highest production cost savings if the congestion was mitigated. These three elements become the subject of three CARIS studies.[42]

A cost-benefit analysis of three generic solutions (representing generation, transmission, and demand response) is conducted in each of the three studies. Resources are placed in key locations to measure the impact over ten years of generator dispatch cost savings, changes in load costs, emissions costs, transmission congestion contract payments, generator payments, losses and installed generating capacity costs. The configurations of the generic solutions are agreed to by stakeholders who participate in the study process. Any stakeholder can request additional analysis for different potential solutions, but must provide funding for the additional work.

The studies go through a process of review and approval before a CARIS report is issued by NYISO:

- Electric System Planning Working Group (ESPWG) and Transmission Planning Advisory Subcommittee (TPAS): Review and makes recommendations
- Business Issues Committee: Reviews and Approves
- Management Committee: Reviews and Approves
- NYISO Independent Market Advisor Review
- NYISO Board: Reviews and Approves
- CARIS Report issued.

In the *project evaluation phase* NYISO makes a request for specific projects to be proposed to meet the CARIS report solutions. NYISO then conducts an updated cost-benefit analysis on each of the proposed projects (using specific costs rather than generic costs). At this time NYISO also determines the beneficiaries of each project and issues a Cost Allocation Report.

A proposed economic upgrade must meet three conditions to be approved to go ahead and be eligible for regulated cost recovery under the NYISO transmission tariff:

1. The benefit must exceed the cost. The benefit is defined as the present value of annual NYISO-wide production cost savings and the cost is the present value of the project's annual total revenue requirement, both over the first ten years the project will be in service.
2. The total capital cost of the project must exceed $25 million.
3. Eighty percent ("a supermajority") of the project beneficiaries must support the project by voting for it in the stakeholder process. Voting shares are weighted in accordance with the Load Serving Entity's share of the total project benefit.[43]

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42 Stakeholders may request additional CARIS studies at their own expense.

43 Where there are multiple Load Serving Entities in a zone the weighted zonal voting share is calculated as (LSE Zonal MWh/Total Zonal MWh) x (Zonal Benefits/ Total Benefits), summed up over all zones for each beneficiary LSE.

3.3.1.4. *Input data assumptions*

NYISO, with input from the TOs on changes to their transmission system and on their load forecast, develops a summer model for the entire New York system. This provides a common modelling framework for the NYISO and TO-led analyses. For example, for the local transmission plan conducted by TOs, the model provides detail for areas outside the TLAs of the local system for the studies conducted, so that the impact of the wider New York system on the TO concerned can be properly modelled. NYISO also provides system information regarding the impacts and potential remedies to congestion and resource integration to help TOs identify solutions in their best interests.

NYISO produces an annual publication known as the "Gold Book"[44] which is publicly available and which contains highly detailed load and capacity data with ten year forecasts for load, generation and transmission additions and retirements, off-system sales and purchases, and detailed data describing the existing system. The Gold Book provides a common basis for all New York planning studies.

3.3.2. *Detailed design, procurement and construction*

TOs undertake the procurement and construction of upgrades identified in the CSPP.

The TOs obtain planning permission/consents, and wayleaves/easements with the New York State PSC and other local authorities as required. TOs manage procurement of the transmission upgrades, which may be through competitive tender to third-party construction companies. The TOs ultimately own the transmission assets.

3.4. Economic regulation arrangements

The arrangements for economic regulation in New York are similar to those in PJM. NYSIO charges customers a transmission tariff (regulated by FERC), and then passes the revenues through to the TOs.

As part of FERC's tariff approval process, NYSIO needs to show that the investment is necessary to comply with the relevant standard, and that it has been identified following the planning process approved by FERC.

New York's cost allocation mechanisms are based firmly on a "beneficiary pays" principle, discussed further below.

3.4.1. *Reliability-based projects*

Cost-allocation for reliability projects is conducted in one of three ways, depending on whether the need is in a specific pre-defined location, whether it is state-wide, or alternatively whether it is bounded by a specific sub-region within New York.

1. *Areas that have identified locational capacity requirements* (currently this category includes New York City and Long Island): If a reliability upgrade is needed to satisfy a

[44] ww.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2011_GoldBook_Public_Final.pdf

reliability issue local to one of these zones then the cost of the project is allocated to the load serving entities in that zone.

2. *Regional reliability projects*: NYISO conducts a simulation of the state using an unconstrained approach where all internal transmission constraints have been relaxed. The simulation determines whether an unconstrained NYISO control area would have a Loss of Load Expectation (LOLE) of less than 0.1 days per year. If not, then the costs of the reliability projects needed to reach this threshold are allocated to all zones based on their peak load contribution, with the zones from Step 1 receiving offset credit for the upgrades they have already funded.
3. *Other projects*: This step only applies if step 2 meets the LOLE threshold and hence, no projects were activated. In this case, the NYISO applies the binding interface test, where binding transmission constraints that prevent sufficient generating capacity from being delivered throughout the NYISO are identified and compensated for through an iterative process of adding resources to the bounded zones with the most impact on reducing the LOLE. Once the iterative process has identified where resources need to be, the costs are allocated to the bounded zone where each project was required in order to compensate for a constraint.

3.4.2. *Economic projects identified under the CARIS process*

The methodology for economic projects is slightly different, but still follows a beneficiaries-pay approach.

If a project meets the eligibility requirements set out at the end of Section 3.3.1.3, the NYISO will identify the project's beneficiaries over the first ten years the project will be in service. Beneficiaries are identified by measuring the present value of annual LMP savings for load in the zones affected by the project, net of reductions in transmission congestion credit payments and the price of bilateral contracts. For each load zone that experiences a benefit, a portion of the project cost is allocated based on their pro rata share of the total savings. Within each zone, the zonal cost is allocated to each load serving entity based on its historic megawatt-hour (MWh) share of consumption.

If the proposed project meets the required super-majority (80%) vote and the project is implemented, then all designated beneficiaries, including those that voted against implementation, will pay their allocated portion of the project costs.

3.4.3. *Direct connections*

NYISO conducts comprehensive studies for the connection of generators and merchant transmission projects to the system. The studies identify Attachment Facilities, which are specifically for connection to the system, and these facilities are paid for by the project proponents.

The studies might also identify System Upgrade Facilities (SUFs) which are any modifications or additions to the existing system that are required for the proposed project to connect reliably to the system. The costs of SUFs are allocated by the NYISO among a "Class Year" of projects. Cost is allocated pro-rata to each project's relative impacts when compared to other projects in the same Class Year. Projects assigned a cost responsibility by

NYISO for SUFs are eligible to be reimbursed by subsequent projects that are able to interconnect utilizing excess capacity provided by the SUFs.[45]

3.5. Reliability standards

The key reliability standards used by NYISO are set by NERC, NPCC, and NYSRC. The oversight by NERC and its delegation of responsibility to a regional entity (in this case NPCC) is equivalent in structure to that of PJM.

3.6. Recent developments

The inclusion of CARIS in the CSPP has been a recent development and was undertaken following FERC's Order No. 890. The methodology of cost allocation for economic projects is still largely untested and it is subject to on-going discussion by NYISO working groups.

45 In practice the the SUFs installed to date have primarily addressed short circuit and system protection issues as well as basic infrastructure to connect the new facilities, and have not included facilities that relieve congestion or increase transfer capability.

4. California

California is part of the WECC (Western Electricity Coordinating Council). WECC encompasses the entire Western Interconnection and covers more than 1.8 million square miles. The Western Interconnection is the geographic area containing the synchronously operated electric grid in the western part of North America, which includes parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming and Mexico and all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington and the Canadian provinces of British Columbia and Alberta. California only generates about 73 percent of the electric power it needs in-state; the remainder is imported from Arizona and Nevada in the Southwest and Oregon and Washington in the Northwest.

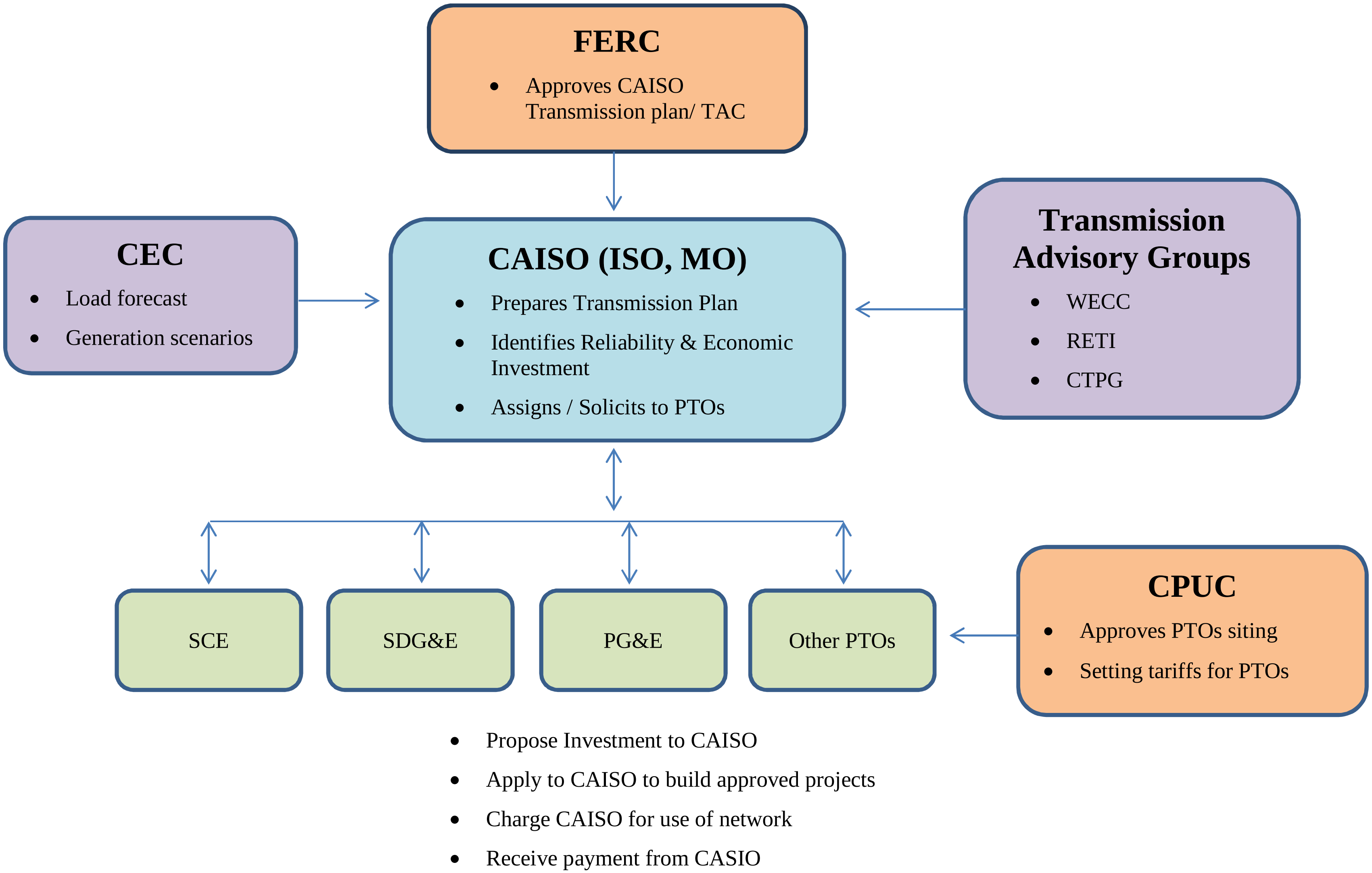
The California legislature passed the state's electric industry restructuring bill "AB 1890" in 1996. Prior to its enactment, generation, transmission, and distribution functions were handled by the state's three major vertically- integrated investor-owned utilities (IOUs): Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). In March 31, 1998, the three IOUs divested the majority of their generation capacity, including gas-fired units, although they retained some of the nuclear and hydro plants and handed over their dispatch control to the California Independent System Operator (CAISO).

4.1. Institutional arrangements

The key institutions and entities relevant to transmission planning in California are as follows:

- The California Independent System Operator (CAISO);
- Other Balancing Authorities;
- Participant Transmission Owners (PTOs) and non-participant transmission owners or merchant transmission investors;
- NERC;
- FERC;
- California Public Utilities Commission (CPUC);
- The California Energy Commission (CEC); and
- Various Transmission Advisory Group

Figure 4.1 - Summary of Key roles and Responsibilities - California



4.1.1. *The California Independent System Operator (CAISO)*

The California Independent System Operator (CAISO) was created by the state of California pursuant to legislation in 1996.[46] The CAISO is the largest of the Balancing Authorities[47] in California, covering 132,000 square miles in portions of all 58 of California's counties. The bulk of the California electricity load is controlled by the CAISO, which operates the flow of electricity in the service territories of California's three main IOUs and several municipal utilities.

The CAISO is a non-profit "public benefit corporation" whose mission is to operate electric grid facilities in California for the purpose of ensuring efficient use and reliable operation of the transmission grid. The CAISO is in charge of developing state-wide transmission planning and assessing transmission proposals from transmission owners and other parties.

The CAISO is governed by a Board of Directors. The CAISO Board consists of five Governors nominated by the governor of California and confirmed by the Senate that serve staggered three-year terms. The Board selection process involving stakeholders was outlined in a FERC order issued July 1, 2005. The Board Nominee Review Committee is comprised of six stakeholders from each of the following member-class sectors: transmission owners, transmission-dependent utilities, public interest groups, end-users and retail energy providers, alternative energy providers, and generators and marketers. Each sector is responsible for selecting its own six members to serve on the committee. Typically, the Committee becomes active beginning late summer each year.

Once the Committee has been established and secretaries nominated, the Board member selection process proceeds as follows:

- An independent search firm creates a list of at least four qualified candidates for each open seat on the Board.
- The list of qualified candidates is then forwarded to the 36-member Board Nominee Review Committee.
- Each member-class sector will select one person to represent the group to conduct a personal interview of selected candidates.
- Based on inputs from the member-class sectors, recommendations are submitted to the Office of the Governor for the State of California.

[46] AB 1890, Cal. Elec. Restructuring Law, Stats.1996, ch. 854 § 1,345, and Senate Bill 96.

[47] A Balancing Authority is the entity responsible for a Control Area, which is equivalent to a "Balancing Area". Balancing Authorities include ISOs and RTOs, but also any other authority outside of an ISO or an RTO in charge of controlling dispatch in real time.

4.1.2. *Other Balancing Authorities*

In the state of California, there are smaller Balancing Authorities that are primarily responsible for controlling the electricity balance within their own service territories but also between Balancing Authorities throughout the state.[48] The largest of these control areas are operated by publicly-owned, vertically-integrated utilities, including Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Utility District (SMUD), Imperial Irrigation District, and Turlock Irrigation District. These utilities are not subject to the jurisdiction of the California Public Utilities Commission (CPUC). They are operated as a department of the City government and regulated by an elected Board of Directors. The California Balancing Authorities must ensure coordination with the neighboring balancing authorities, including Pacificorp in Oregon, NV Energy in Nevada and the Federal Agency Bonneville Power Administration (BPA). BPA is connected to the California high-voltage transmission system through path 66, which consists of two 500 kV AC lines of the Pacific AC Intertie and a third 500 kV AC line of the California-Oregon Transmission Project. Combined, these three lines are operated as the “California-Oregon” Intertie.

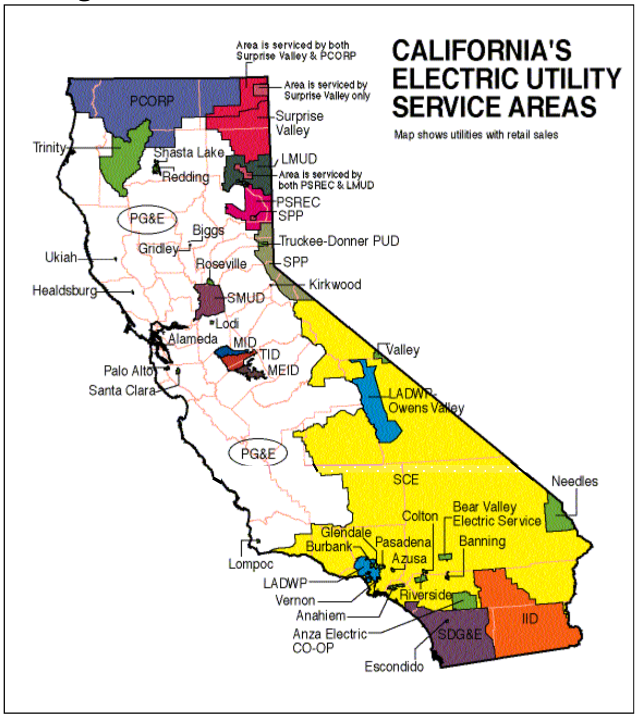
4.1.3. *Participant Transmission Owners (PTOs)*

In California, transmission owners that place their transmission facilities and entitlements under the CAISO’s operational control are referred to as “Participant Transmission Owners” (PTOs). A Transmission Control Agreement (TCA) is the agreement among the CAISO and PTOs and establishes the terms and conditions under which transmission will be placed in CAISO’s control. The three IOUs (SDG&E, SCE and PG&E) are the major PTOs in California, and together own around 80 percent of the total transmission capacity in California, in addition to distribution wires. Over time, a number of amendments to the TCA have been made to add new participating transmission owners and for other purposes.

The service territories of PG&E, SCE and SDG&E collectively represent about 68 per cent of the state’s load. Figure 4.2 illustrates the service territories of the main utilities (which is the area covered by the CAISO) as well as the areas covered by the other balancing authorities in California.

[48] The NERC definition of Balancing Authority is**:** “One of the regional functions contributing to the reliable planning and operation of the bulk power system. The Balancing Authority integrates resource plans ahead of time, and maintains in real time the balance of electricity resources and electricity demand.”

Figure 4.2 - California Service Territories



As the transmission provider, the CAISO is the primary responsible for planning and operating the transmission grid.

The PTO is responsible for building, owning and financing projects or upgrades located within its PTO Service Territory when the CAISO has determined that these are needed for reliability or to maintain the feasibility of Long-Term Congestion Revenue Rights or CRRs (discussed in Section 4.2.1 below).

The PTO also owns the transmission facilities to which generating facilities are connected, and is responsible for constructing or modifying and maintaining any transmission facilities required to allow an interconnection that has been approved by CAISO.

Under the existing CAISO transmission planning process, all transmission project sponsors, including both independent (non-participant) transmission developers and PTOs, have an equal opportunity to propose to construct and own any policy-driven transmission facilities and other transmission projects that provide economic benefits, provided that the CAISO has first found it to be needed in its planning process.

4.1.4. *NERC*

NERC's role in California is the same as in PJM and New York. The regional entity to which NERC has delegated authority is the WECC (refer to Figure 2.3 – North American Regional Reliability Councils and Interconnections).

4.1.5. *FERC*

FERC's role in California is very similar to that in PJM and New York.

FERC approves the transmission planning processes of CAISO.

4.1.6. *The California Public Utilities Commission (CPUC)*

The CPUC regulates California's privately owned electric, natural gas, water, railroad, telecommunications, rail transit, and passenger transportation companies.

The specific responsibilities of the CPUC relating to energy include:

- reviewing and approving the IOUs' long term procurement plans;
- setting electricity rates (i.e., tariffs);
- issuing transmission siting permits;
- issuing a "Certification of Public Necessity and Convenience";
- protecting consumers;
- promoting energy efficiency; and
- ensuring electric system reliability.

4.1.7. *The California Energy Commission (CEC)*

The California Energy Commission (CEC) is an institution which is unique to California. The responsibilities of the CEC include:

- Forecasting future load and generation development scenarios and tracking historical energy data;
- Siting and licensing thermal power plants 50 megawatts (MW) or larger to meet statewide energy needs;
- Promoting energy efficiency by setting California's appliance and building standards and working with local governments to enforce those standards;
- Supporting renewable energy by providing market support to existing, new and emerging renewable technologies;
- Implementing California's Alternative and Renewable Fuel and Vehicle Technology Program; and
- Planning for and directing state response to energy emergencies.

The CEC, in coordination with the CPUC, CAISO, and other governmental entities, is required to produce an integrated energy policy report every two years that includes assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices. The CEC's integrated policy report also generally assesses system reliability and the need for resource additions. The CEC, therefore, provides a high level analysis that is utilized by the CAISO, including in its transmission planning role.

The California Governor appoints the five members of the CEC to staggered five-year terms and selects a chair and vice chair from among the members every two years. The appointments require Senate approval. By law, one commission member must be selected from the public at large. The remaining commissioners represent the fields of engineering / physical science, economics, environmental protection, and law. The Commission receives its funding from an electricity consumption surcharge collected by the electric utilities through customers' bills and then transferred to the state treasury.

4.1.8. *Transmission Advisory Groups*

In addition to the federal and state energy regulatory authorities, the ISO and the other Balancing Authorities, other groups have formed in recent years to address transmission planning in California. These are as follows:

- The Western Electricity Coordinating Council (WECC) is the Western Interconnection-Wide Planning Facilitator and provides planning functions (transmission planning and integration of resources) and policy-related functions as requested by the CAISO and CPUC.
- The California Renewable Energy Transmission Initiative (RETI) is an initiative launched by the CPUC, the CEC, CAISO, and California's IOUs in 2007, to help identify the transmission projects needed to accommodate California's renewable energy goals, support future energy policy, facilitate transmission corridor designation and transmission and generation siting and permitting.
- The California Transmission Planning Group (CTPG) is a group of incumbent transmission owners with service territories and transmission operators (i.e., parties that have both the responsibility for transmission planning and the technical capabilities to perform the required activities). They were brought together to discuss how to address California's current and future transmission needs. CTPG evaluates alternative renewable resource portfolios based on participant interest and reflecting input from RETI, other stakeholders and state agencies. One explicit CTPG objective is to identify opportunities for joint transmission projects, i.e., projects across different balancing authority areas, which the CAISO believes is an important focus and potential benefit of developing a statewide 33% renewable transmission plan.

4.2. Planning process

4.2.1. *Planning principles*

A core responsibility of the CAISO is to plan and approve additions and upgrades to transmission infrastructure, to ensure that as conditions and requirements evolve over time it can continue to provide a well-functioning wholesale power market through reliable, safe and efficient electric transmission service.

The goals driving transmission planning vary depending on the type of project. Transmission projects may fall into several specific categories, including:

- Reliability-driven transmission projects;
- Economic transmission projects (i.e., those driven by market benefits);
- Location Constrained Resource Interconnection Facilities (LCRI);
- Long-term Congestion Revenue Right (CRR) Feasibility projects;
- Merchant transmission projects; and
- Policy-driven projects (including those related to renewable energy).

Network projects that are considered reliability-driven are judged according to standard planning criteria used to quantify system performance as provided by the NERC, the WECC, and CAISO in their planning standards.

Economically-driven network transmission projects include those projects where the economic benefits of the upgrade or addition (primarily lower energy production costs. including generation cost dispatch and losses, in the region, reduced congestion, or lower generation capacity needs) are expected to exceed the project costs. Economically-driven projects can be proposed by a TO, a market participant, the CPUC, or the CEC, and they are approved if they are found to be beneficial according to CAISO's evaluation methodology.

The LCRI projects are intended to support the connection of remote renewable energy resources to the California grid. Total investment in LCRI facilities is capped at 15% of the total of the net high-voltage transmission assets of participating transmission owners in the CAISO.

Long-term Congestion Revenue Right (CRR) feasibility projects include transmission upgrades identified by the CAISO during its annual transmission planning cycle (discussed in detail below) to ensure the feasibility of previously released long-term CRRs for their full ten-year term. If any such upgrades are found to be needed, their costs are recovered through the CAISO's Transmission Access Charge.

Merchant projects are transmission upgrades and additions undertaken by parties other than PTOs. Once constructed, operational control of the transmission lines is turned over to CAISO and the developer will not receive rate-based recovery of the investment cost through the Transmission Access Charge (TAC). The merchant is eligible to receive an allocation of the 30-year option CRRs (merchant CRRs) in a quantity that reflects the incremental capacity the merchant project adds to the CAISO grid.

In June 2010, FERC required ISOs and RTOs and other transmission providers to incorporate state and federal public policy-driven transmission projects into their transmission planning. Policy-driven projects include those required to remote renewable resources to the grid. RETI helps identify the transmission projects needed to accommodate the 33% renewable energy by 2020 goal, and facilitate transmission corridor designation and transmission and generation sitting and permitting. RETI is in charge of assessing Competitive Renewable Energy Zones (CREZ), i.e., areas with concentration of high-quality renewable resources that can be delivered to California loads and possibly also in neighboring states. RETI prepares detailed transmission plans for those zones identified for development. Much of the data used by the CPUC in developing its generation development scenarios and by the CAISO in further refining those scenarios for use in the transmission plan is initially developed through RETI.

4.2.2. *Market-wide planning*

The CAISO identifies, evaluates, and approves new transmission facilities through its annual Transmission Planning Process (TPP). The CAISO seeks input from stakeholders, neighbouring Balancing Authorities and other planning entities, including the CTPG, the RETI and the WECC, at each major step of the process. In general, at least four public stakeholder meetings are held in a planning cycle. Stakeholders are also asked to provide input, comments, or recommendations on the upgrades to the CAISO study results, as explained below. The TPP covers a five-year planning horizon. The process consists of three phases covering a 23-month period starting from December of the year prior to year one and continuing through October of the following year.[49]

With FERC's approval of the CAISO's revised TPP in December 2010, two important new elements were incorporated into the TPP beginning with the 2011/2012 planning cycle:

- the specification of public policy objectives for transmission planning; and
- the development of a "Conceptual Statewide Transmission Plan", as an input for consideration in developing the CAISO's comprehensive transmission plan.[50]

As part of the TPP process the CAISO has the responsibility to identify "high priority projects", i.e. upgrades and/or additions that address (a) congestion identified by the CAISO in the applicable transmission planning process cycle; (b) local capacity area resource requirements; (c) congestion projected to increase over the planning horizon used in the transmission planning process; or (d) integration of new generation resources or loads on an aggregated or regional basis. The CAISO is then responsible for undertaking the high-priority economic planning studies included in the comprehensive transmission plan, for which the CAISO assumes cost responsibility. The load forecasts used in the study are developed by the CEC.

The "phases" that form the TPP, are:

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[49] For example, the 2012/2013 TPP began in December 2011.

[50] The Conceptual Statewide Transmission Plan was incorporated in the CAISO TPP based on the recognition that public policies such as the 33% RPS could necessitate the development of new transmission infrastructure affecting not only to the CAISO BA (Balancing Authority), but also the entire state. For this reason, although the CAISO's responsibility is to plan and approve transmission projects for its own BA, collaboration with other California transmission providers was considered necessary in developing new transmission most efficiently to meet the statewide 33% RPS mandate. However, although such a plan is useful in providing a broad geographic view of needed transmission development, the plan is only "conceptual" in the sense that it is for informational purposes only and not binding on any of the California transmission providers as to which projects must be approved. Each California transmission provider remains responsible for approving transmission for its own BA.

1. Development of Unified Planning Assumptions, Study Plan, and initiation of the "conceptual" *Statewide* Transmission Plan.

2. Performance of technical studies, and development of the comprehensive CAISO Transmission Plan.

3. Selection of project sponsors for the identified transmission elements.

These three phases are described below.

4.2.2.1. *Phase I*

Phase I begins with a "stakeholder input" period for approximately one month, typically starting in mid-December. During this time the CAISO sends a market notice to all interested parties and a letter to neighbouring balancing authority areas, sub-regional and regional planning entities requesting certain planning information that the CAISO might consider when developing the unified planning assumptions and the draft Study Plan.

The development of Unified Planning Assumptions and Study Plan starts in January of each year. During the first stakeholder meeting, the CAISO issues a draft Study Plan, which includes information about the technical studies to be undertaken by the CAISO. Following the publication of the draft Study Plan, stakeholders and other TPP participants may submit comments on the scope and contents of the draft Study Plan. Interested parties may also submit Economic Planning Study Requests (see below). The objective of this process is to determine the goals, agree on data assumptions and inputs for creation of a base case, identify necessary modifications to the base case for individual technical studies, identify the technical studies to be performed as part of the TPP cycle, and allow TPP Participants to review and comment on the scope of the upcoming technical studies.

During this phase, TPP participants will be given an opportunity to provide comments regarding demand response programs[51] requested to be included in the base case, as well as generation and non-transmission alternatives[52] proposed for consideration and inclusion in the draft Study Plan.

Stakeholders may submit requests to the CAISO to perform an "Economic Planning Study" specific to a congested transmission area. Economic Planning Study Requests must identify the congested transmission element (binding constraint), limiting facilities, or other matters to be studied. The request should also include other information supporting the potential for increased future congestion on the binding constraint.

The CAISO evaluates and prioritize the Economic Planning Study Requests for purposes of consideration in the Transmission Plan. The CAISO selects "High Priority Economic Planning Studies", based on at least one of the following:

[51] The submitter must be able to provide a bus-level model of demand response assumptions for power flow or stability studies and associated planning level costs. In addition, submitters must provide satisfactory evidence showing that the proposed demand response will be reliably operated and controllable by the CAISO, as well as having received appropriate regulatory approval as part of the Resource Adequacy or other similar program such as the CPUC's Long Term Procurement Process (LTPP).

[52] At a minimum, the submitter must be able to provide the information necessary for these alternatives to be modeled in the planning studies. This information includes, but is not limited to, project location, project costs, size, power flow and dynamic models, project scope and detailed descriptions of the characteristics or how it will be operated.

- Whether the requested study seeks to address transmission congestion identified by the CAISO.
- Whether the requested study seeks to reduce or address the need for local resource adequacy resources in the local area.[53]
- Whether resource and demand information indicate that the congestion described in the request is projected to increase over the planning horizon used in the TPP, and the projected magnitude of the congestion.
- Whether the Economic Planning Study is identifying upgrades necessary to integrate new generation resources or loads on an aggregated or regional basis.

In each planning cycle, the CAISO may include up to five potential High Priority Economic Planning Studies in its Study Plan.[54] After the closing of the comment window, the CAISO will review stakeholder comments, evaluate Economic Planning Study Requests, select the High Priority Studies and publish the final Study Plan.[55]

The Conceptual Statewide Transmission Plan is developed in parallel to the stakeholder discussions in Phase I by CAISO, in coordination with neighbouring balancing authority areas, and other regional or sub-regional transmission planning groups or entities. This plan identifies potential transmission upgrades, additions or other investments needed to meet state and federal policy requirements and directives.

The CAISO posts the conceptual statewide plan to its website and stakeholders have a twenty day comment period. Comments and recommendations to the conceptual statewide plan are considered as an input into the CAISO's Phase 2 evaluation process, and ultimately will lead to the development of the comprehensive Transmission Plan.

4.2.2.2. *Phase 2*

Phase 2 of the CAISO TPP is a 12-month period that starts in April of the first year through March of the following year. During this phase the CAISO conducts technical studies to determine the needs for transmission additions and upgrades. These studies are required to identifying potential physical and economic limitations of the CAISO Balancing Authority Area and assess the upgrades needed to maintain or enhance system reliability, promote economic efficiency, or maintain the feasibility of Long Term CRRs. The studies look at the next five years but also consider long term scenarios (10 years).

The CAISO's "Request Window" in Phase 2 is to solicit submission of specific project proposals for certain categories of transmission. The following categories of transmission projects, as well as demand response and generation proposals to be studied as alternatives to transmission upgrades, may be submitted through the request window:

- Reliability projects, identifying the reliability need for which the reliability-driven project is being submitted and a description of the upgrades, costs, schedules and benefits of the project in terms of mitigating specific reliability concerns;

[53] These could include (but are not limited to) generation with network support contracts.
[54] However, the ISO retains discretion to perform more than five High Priority Economic Planning Studies if stakeholder requests or patterns of congestion or anticipated congestion so warrant.
[55] High priority economic studies are economic planning studies performed by the CAISO and included in the comprehensive transmission plan for which the CAISO assumes cost responsibility.

- Merchant projects, i.e., transmission upgrades or additions for which a project sponsor does not seek cost recovery through the CAISO's transmission access charge, but rather funds the project itself and recovers its costs through merchant CRRs; currently, any market participant or PTO may act as a Project Sponsor to identify a possible transmission upgrade and seek its incorporation into the CAISO TPP for ultimate approval and construction as a Merchant Transmission Facility.

- Transmission projects proposed to connect Location Constrained Resource Interconnection Facilities (LCRIF)[56] in designated Energy Resource Areas.

- Demand response programs or generation resources to be studied as alternatives to needs identified in the CAISO technical studies, provided they have been approved by the CPUC or appropriate local regulatory agency.

- Projects needed to maintain the feasibility of Long-Term CRRs.

If a proposed transmission project is sub-regional or regional and affects other interconnected Balancing Authority areas, the project proponent must provide information on whether the proposal has been reviewed by the appropriate sub-regional and/or regional planning entity, and whether it has been determined by such entity to be:

- consistent with that planning entity's preferred solution; and
- appropriate for inclusion in the CAISO study plan rather than, or in addition to, being included in or deferred to the planning processes of the regional or sub-regional planning entity.

The CAISO performs reliability studies to identify upgrades or additions to ensure system reliability, in accordance with the tariff. The CAISO may assign technical studies or portions of technical studies to Project Sponsors or the PTOs to perform.[57]

Results of technical studies conducted by the CAISO as well as those conducted by the PTOs or others at the direction of the CAISO are posted by August 15 of each year. Once the study results have been posted, PTOs must submit specific transmission project proposals within thirty days through a "Request Window". The Request Window opens following the publication of the technical study results, on August 15th and closes on October 15th.

During Phase 2, the CAISO may also undertake economic analysis to assess whether transmission upgrades or additions could provide additional ratepayer benefits, using a monetary metric that measures benefits against costs. Benefits may include reduced production costs, congestion, capacity costs, losses or environmental costs. Costs, in addition to the cost of the transmission facilities, also include the cost to maintain the simultaneous feasibility of long-term congestion revenue rights. [58]

Once the Request Window is closed and comments on the conceptual statewide plan have been received, the CAISO develops a preliminary comprehensive Transmission Plan for the

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56 These connect location constrained generators to the CAISO grid.

57 In particular, when dealing with specific generator connection requests, the CAISO may direct the applicable PTO to perform portions of the studies where the PTO has specific and non-transferable expertise or data and can conduct the studies more efficiently and cost effectively than the CAISO.

58 Details on the benefit-cost framework can be seen in California ISO, Transmission Economic Assessment Methodology (TEAM), June 2004 which outlines in detail how the CAISO evaluates economic transmission upgrades.

CAISO footprint which identifies all projects needed to maintain reliability, LCRIF projects, projects to maintain LT-CRRs, qualified Merchant Transmission Facility projects, and needed Network Upgrades. Further evaluation of the preliminary comprehensive Transmission Plan may yield the need to assess additional transmission upgrades to meet state or federal policy requirements or directives as specified in the Study Plan.

At the end of this phase, the CAISO develops the comprehensive Transmission Plan, which describes the study results and identifies transmission projects. The development of the draft, and ultimately the final comprehensive Transmission Plan is based on the preliminary Transmission Plan and on additional analysis that may identify certain policy-driven elements as well as the inclusion of an economic analysis of the preliminary plan. Once the policy-driven elements and economically driven elements of all projects have been determined, the CAISO revises its preliminary comprehensive Transmission Plan.

4.2.2.3. *Phase 3*

The draft comprehensive Transmission Plan is posted on the CAISO website and presented to TPP Participants for review and comment during the 4th public meeting which is held in the first quarter (approximately February) of each year. After collecting TPP Participant comments, the comprehensive Transmission Plan is finalized and presented to the CAISO Governing Board for approval in March of each year. Once approved, the CAISO posts the final comprehensive Transmission Plan on the CAISO Website and advises interested parties of the website location.

Included in the revisions to CAISO transmission plan that took place in 2010[59], was a distinction between projects under Category 1 (transmission elements that will be recommended to the CAISO board for approval as part of the transmission plan) and Category 2 (transmission elements that will be identified but re-evaluated in future cycles). This was done in order to manage the risk of stranded investment associated with transmission additions that may need to be reassessed based on new information regarding generation development and other factors.

Solicitation of transmission proposals

In Phase 3, no later than April 1 following the publication of a final CAISO-Board approved comprehensive Transmission Plan, the CAISO will post a market notice announcing a competitive solicitation process[60] through which the CAISO will expect to receive proposals to finance, construct, and own any project that is deemed to be either: (a) economically-driven or (b) policy-driven, under Category 1 provided that these projects have been approved by the Board in the draft Plan at the end of Phase 2. The notice specifies that all proposals must be received by the CAISO no later than the following June 1.

In principle, the solicitation projects are not expected to include projects that only provide reliability benefits or long-term CRR feasibility, since these remain under the responsibility of the incumbent transmission owner. However, if a reliability project or long-term CRR feasibility project is considered to provide economic benefits, equivalent to or greater than

[59] The Revised Transmission Planning Process (RTPP) was filed on June 4, 2010 by the CAISO at FERC. In an order issued on December 16, 2010, FERC approved the CAISO's filing subject to certain limited modifications to the ISO tariff, to be effective as of December 20, 2010.

[60] The CAISO has not yet tried to select a project under its competitive solicitation process.

ten percent of the cost of the project, the CAISO will re-categorize the project and make it subject to a competitive solicitation process as an economic project. The CAISO contends that ten percent is an appropriate threshold because it is low enough to broadly expand the pool of resources eligible for competitive solicitation, but high enough to exclude projects with *de minimis* economic benefits. The FERC agreed with this approach.

Within ten business days after receiving the form and accompanying information on a proposal, the CAISO determines whether the proposals include the information necessary for the CAISO's evaluation. The CAISO's existing competitive solicitation process does not differentiate between the costs of high voltage facilities that are allocated regionally across the entire CAISO footprint versus the costs of low voltage transmission facilities that are allocated only within the service territory of a single PTO.

No later than June 21 following the publication of a final comprehensive Transmission Plan, for all submitted proposals, CAISO will review sponsor qualifications and consistency of proposal with plan specifications and applicable standards. The screening criteria will involve, in particular:

- Whether the proposed project is consistent with needed transmission elements identified in the comprehensive Transmission Plan (e.g., in the case of economic projects, CAISO will evaluate if the proposed project is in fact going to effectively reduce the expected congestion identified by CAISO during the planning process);
- Whether the proposed project satisfies Applicable Reliability Criteria and the CAISO Planning Standards; and
- Whether the Project Sponsor is considered to be physically, technically, and financially capable of (a) completing the project in a timely and competent manner; and (b) operating and maintaining the facilities consistent with Good Utility Practice and applicable reliability criteria for the life of the project. This evaluation will involve a review of project sponsor's prior record on building and maintaining projects, including demonstrated ability to meet schedules and use cost containment measures.

If multiple project sponsors for the same transmission element meet the qualification requirements or screening criteria as identified above, the CAISO will give an opportunity for the project sponsors to collaborate with each other to propose a single joint project. If project sponsors are unable to collaborate on a single project and all propose to seek siting authorization from the same siting authority, the CAISO will defer to the siting authority to determine which project sponsor should build and own the project. If not all project sponsors are expected to seek authorization from the same siting authority, the CAISO will decide which project sponsor should build and own the project. The CAISO must engage an expert consultant to assist with the selection of the approved project sponsor.

When presenting their proposals, a project sponsor may, voluntarily, commit to a binding cost cap, which may reflect favorably on its proposed project at the time of selecting a project sponsor. However, unless the project sponsors commit to a cost cap, the CAISO will not consider the project sponsors' cost estimates in its selection process since any cost estimates are unenforceable by CAISO and therefore project sponsors may have an incentive to underestimate their costs.

If the project sponsor that gets selected in the competitive solicitation is unable to secure all necessary siting approvals and is deemed unable to complete the project, the CAISO may then decide to either assign the project to the PTO in the service territory where the transmission project is expected to be located, or conduct an additional solicitation. In considering whether to hold an additional solicitation, the ISO considers such factors as the number of project sponsors who submitted proposals to finance, own and construct the element in the initial tender and the needed online date for the element.

If the project gets assigned to the PTO, the PTO has the responsibility to construct, own and finance such elements. However, if the applicable PTO, after making a good faith effort, was not able to obtain all necessary approvals and property rights under applicable federal, state and local laws, the PTO would notify the CAISO and the CAISO would convene a technical meeting to evaluate alternative proposals. The CAISO would take any action to develop and evaluate alternatives, including the discretion to confer the right to construct, own and finance the transmission addition or upgrade on a third party.

4.2.3. *Localised planning*

As part of the annual transmission planning cycle, the CAISO performs a five-year Local Capacity Requirement (LCR) study to provide visibility to stakeholders relating to local capacity requirements across the five year time horizon. The LCR study is intended to forecast potential LCR needs over a five year planning horizon that can inform the CAISO's comprehensive planning process and identify the need for longer lead time economically-driven transmission elements. The study uses load forecasts developed by the PTOs in their service territories from the CEC load projections. This is used as the starting point as the load forecast from the CEC do not generally provide the bus-level demand projections.

This study is different from the Local Capacity Technical Study methodology that the CAISO undertakes with only a one-year horizon for purposes of the CPUC's resource adequacy development process. In the LCTS, local capacity requirements are used as the basis for procurement of resource adequacy capacity by load-serving entities for the following resource adequacy compliance year and also provide the basis for determining the need for any ISO "backstop" capacity procurement that may be needed once the load-serving entity procurement is submitted and evaluated.

Both studies assess the minimum level of capacity needed to ensure reliable system operation under peak demand conditions consistent with NERC and WECC standards and CAISO planning standards. The studies also evaluate the definitions of the existing local areas and may potentially identify the changes in local areas or sub-areas definitions due to the impacts of system topology changes. Both studies utilize a similar methodology, but evaluate different time horizons.[61]

[61] Detailed study assumptions, methodology, tools, and other information necessary for the studies are found in the Local Capacity Technical Study Manual posted to the CAISO Website at Transmission Planning.

4.3. Investment decision roles and responsibilities

4.3.1. *Investment decision making*

The responsibilities regarding decision making can be summarized as follows:

- CAISO is solely responsible for investment decision making.
- CAISO receives input from transmission owners and other stakeholders in making its assessment.
- If the system suffers an outage due to insufficient transmission investment or upgrading, the CAISO will bear responsibility. The CAISO liability from third party claims is subject to limitations as specified in the CAISO's Transmission Control Agreement. The CAISO insures itself against this liability.
- Once the CAISO Board has approved project proposals to meet the identified needs (or policy-driven projects), the PTOs or other project sponsors may be assigned responsibility for construction and if so they will seek siting approval from the CPUC, which has sole jurisdiction over this facet of the industry.
- The CAISO adopted standards for the maintenance of transmission facilities, as mandated by the California Legislature. All transmission owners must comply with the CAISO maintenance practices and submit a biannual maintenance report for review by the CAISO.

In determining the grid needs, the CAISO collects the necessary information and adopts a number of assumptions to be used in the TPP, including, but not limited to, those related to demand forecasts, potential generation capacity additions and retirements, and expected transmission system modifications such as upgrades or additional projects that have been approved by the CAISO in past planning cycles as part of the comprehensive Transmission Plan for that earlier cycle.

4.3.1.1. *CAISO*

CAISO is solely and ultimately responsible for making the grid need assessments, but it receives input from transmission owners and other stakeholders. The FERC is the federal regulatory agency with jurisdiction over high voltage transmission systems as well as the wholesale energy markets, and the ISOs and market participants must adhere to its general Orders concerning planning and open access.

The CAISO takes into account future growth in electricity demand and the need to meet state energy and environmental goals.

The CAISO adopted standards for the maintenance of transmission facilities, as mandated by the California Legislature. All transmission owners must comply with the CAISO maintenance practices and submit a biannual maintenance report for review by the CAISO. If the system suffers an outage due to insufficient transmission investment or upgrading, the CAISO will bear responsibility.

CAISO takes studies supplied by PTOs to produce an annual transmission planning report, which must be approved by the CAISO Board of Governors. Once the CAISO Board has approved project proposals to meet the identified needs (or policy-driven projects), the PTOs seek siting and construction approvals from the CPUC, which has sole jurisdiction over this facet of the industry.

4.3.1.2. *The California PUC*

The CPUC reviews and approves demand management resources before they can be submitted into the CAISO "request window" during the transmission planning process. In addition, the CPUC reviews any permit applications for transmission projects (those above 50 kV) submitted by the PTOs or merchant transmission companies, under two concurrent processes:

- An environmental review, pursuant to the California Environmental Quality Act (CEQA), and
- A review of "Project need and costs" pursuant to the Public Utilities Code (PU Code)[62]

The CPUC is responsible for approving siting of transmission and granting a "Certification of Public Necessity and Convenience" (CPCN), for transmission projects at 200 kV and above, or a "Permit to Construct" (PTC), for projects between 50kV and 200kV.

- If a project is > 50 kV but less than 200 kV the CPUC primarily undertakes an environmental review pursuant to the CEQA, but does not analyze the need for or economics of the project.
- If a project is > 200kV, the CPUC analyzes the need for the project, expected impact on rates and other factors, in addition to environmental impact of the project.

The CPUC relies on the ISO's technical expertise to identify (a) the transmission infrastructure needed to maintain a reliable service, as well as (b) the transmission that will help meet policy goals such as the state's Renewables Portfolio Standard (RPS). However the CAISO, not being a government agency, is not required to comply with CEQA during its transmission planning process. There is a risk that the CAISO will approve a project which the CPUC will later reject as not needed pursuant to the CEQA or other considerations. If a project is considered not needed it is not eligible to receive ratepayer funding.

In April 2011, the CPUC and CAISO executed a "Memorandum of Understanding" that sets out guidelines aimed to ensure that the CPUC transmission permitting process will be sufficiently coordinated with the CAISO's transmission planning. In the memorandum, the CPUC agrees to make sure that its siting/permitting process will give substantial weight to 'project applications that are consistent with the ISO's final Phase 2 plan". Additionally, CAISO uses data from the CPUC long-term procurement proceedings and coordinates its scenario development with the scenarios developed by the CPUC staff for use in evaluation of renewables-related projects. This memorandum responds to claims by renewable developers that the CPUC's discretion creates too much uncertainty at the time of pursuing Power Purchase Agreements (PPAs) for solar and wind development with a utility.

[62] Sections 1001 et seq. and General Order (G.O.) 131-D (Certification of Public Necessity and Convenience (CPCN) or Permit to Construct (PTC)).

4.3.2. *Detailed design, procurement and construction*

4.3.2.1. *Reliability-driven projects*

PTOs have the responsibility to construct, own and finance projects or elements determined by the CAISO to be needed where the additions or upgrades to the transmission facilities are *reliability*-driven projects located within its TO Service Territory or for projects needed to maintain the feasibility of Long-Term CRRs.

For any other projects, such as those economically-driven or policy-driven projects, the TO will be required to construct and finance those projects if there are no approved Project Sponsors, or the Approved Project Sponsor is unable to secure all necessary approvals. The TO is responsible for the detailed design of the transmission asset and must obtain the required siting approval from the CPUC.

4.3.2.2. *Economically or policy-driven projects*

If only one project sponsor has submitted a proposal to finance, construct, and own an economically-driven or policy driven transmission element identified in a final comprehensive Transmission Plan, and the CAISO determines that the project sponsor is qualified to finance, construct and own the project under specific criteria set forth by CAISO, then the Project Sponsor must commence the process to seek siting approval, and any other necessary approvals, from the appropriate siting authority within sixty calendar days of ISO approval. The project sponsor must provide the ISO with documentation that it has commenced the process to seek siting approval and other necessary approvals.

When two or more project sponsors submit proposals to finance, construct, and own the same economically-driven or policy driven transmission element or elements and the CAISO determines that two or more of those project sponsors meet the criteria, the CAISO must engage an expert consultant to assist with the selection of the approved project sponsor. Thereafter, the approved sponsors must seek siting approval, and any other necessary approvals, from the appropriate authority or authorities within 120 days of CAISO approval.

4.4. Economic regulation arrangements

The arrangements for economic regulation in California can be summarised as follows:

- CAISO charges all customers connected to the transmission system a Transmission Access Charge (TAC), which includes all of the existing TOs' transmission revenue requirement for the infrastructure in place, plus any revenue requirement associated with projects that are coming into effect in the planning year, all of which have been approved by FERC. The revenues from TAC are then passed to the respective TOs who built the transmission.

- The costs of transmission facilities below 200 kV are not included in the system-wide CAISO's TAC since they do not provide system-wide benefits. These costs are exclusively recovered from CPUC-approved tariffs that are charged to those customers connected to the transmission system in the TO's service territory. These retail CPUC-approved tariffs include as well the corresponding share for the high-voltage transmission revenue requirement that has been allocated by FERC to all load in the state.

- FERC ultimately oversees CAISO's decision as to what high-voltage transmission investments have been approved for construction.

4.4.1. *Reliability and economically-driven upgrades*

California effectively has a postage stamp rate for transmission projects that are either reliability or economically-driven provided that they are at 200 kV and above and have been approved by the CAISO. These costs are allocated to all transmission customers on a megawatt-hour (MWh) basis across all load in the CAISO through the Transmission Access Charge (TAC). Lower voltage transmission costs are exclusively recovered through zonal charges from customers located within the service territory of each PTO. Local customers or the PTO also contribute to the recovery of high-voltage transmission facilities through their rates, that is, the TAC-related revenue requirement corresponding to their load, based on their contribution to the 12 monthly CAISO-system coincident peak.

4.4.2. *Direct connections*

Generally, the generation developer is 100 percent responsible for the cost of direct connection facilities. If the network upgrades take place to accommodate a planned connection of a large generator facility, the generator owner may be required to pay for the capital costs upfront. However, the TO may, at its own election, agree to initially pay for the necessary network upgrades, thereby relieving the generator owner of the upfront capital costs.

The capital costs of the network upgrades are "rolled-in" to general transmission rates of the PTOs and recovered through CAISO's grid-wide TAC, subject to FERC oversight and approval. The generator owner is entitled to be reimbursed for these costs, with interest, as revenues are collected from customers using the PTOs' OATTs, provided that such amount is paid within five years of the line's commercial operation date.

Instead of direct payments, the interconnecting generator developer may elect to receive Congestion Revenue Rights (CRRs) in accordance with the CAISO Tariff associated with the specific network upgrades that were funded by such generator, to the extent such CRRs are available under the CAISO Tariff at the time of the election. Such CRRs would take effect upon the commercial operation date of the generating facility.

4.4.3. *LCRIF*

The CAISO currently permits a unique approach in the case where transmission projects are necessary to connect generators in certain remote areas. The costs for these LCRIF are socialized and recovered through MWh-based charges to load before generators are connected, at which time costs are assigned to such generators going forward on a pro-rata basis until the line is fully subscribed and at that point the transmission owner is "re-paid" for its initial investment.

Merchant Transmission Facilities, whose costs are paid by a project sponsor that does not recover the cost of the transmission investment through CAISO transmission charges, may obtain Merchant Transmission Congestion Revenue Rights.[63]

4.5. Reliability standards

There are three types of planning standards that the CAISO needs to satisfy:

- NERC Planning Standards
- WECC Planning Standards
- CAISO Planning Standards

The reliability standards developed through NERC are regulated and enforced by FERC. The following NERC reliability standards are applicable to the CAISO as a registered NERC Planning Coordinator and are considered in the reliability assessments:

- TPL-001: System Performance Under Normal Conditions (Category A);
- TPL-002: System Performance Following Loss of a Single Bulk Electric System (BES) Element (Category B);
- TPL-003: System Performance Following Loss of Two or More BES Elements (Category C);
- TPL-004: System Performance Following Extreme BES Events (Category D).

In addition, WECC Reliability Standards are applicable to the CAISO as a member of the WECC. The WECC Reliability Standards, like the NERC reliability standards, set forth additional criteria for meeting system performance requirements that must be met under a varied but specific set of operating conditions.

Finally, the CAISO Grid Planning Standards (ISO standards) specify the planning standards to be used in the planning of CAISO transmission facilities. These standards address specifics not covered in the NERC reliability and WECC planning standards. At this point the CAISO Grid Planning Standards define a more stringent requirement for all TPL-002 disturbances than is specified by the NERC reliability and WECC planning standards. For the CAISO, acceptable system performance for the TPL-002 standard is bound by loss of a single bulk electric system element when one generator is already out of service, where NERC and WECC define the TPL-002 standard as system performance following loss of a single bulk electric system element

[63] Detailed information on transmission expansion can be found in the California ISO Tariff, Section 24, and in Appendix F, Schedule 3 with respect to the manner in which this is recovered from load.

4.6. Recent developments

Of note is a current proceeding in relation to renewable-related transmission project cost recovery.

Effective January 1, 2011, Assembly Bill (AB) 1954 Section 399.2.5 was amended in order to provide ‘backstop’ cost recovery mechanisms for transmission facilities that have not been approved by the FERC for recovery through wholesale transmission rates. Under the amendment section, utilities would be allowed to recover the costs of these projects through retail rates. This amendment is expected to allow utilities to proceed with the development of transmission facilities that are “necessary to help attain” Renewable Portfolio Standards (RPS). CPUC Decision D.07-03-012 established three requirements that must be met in order to apply for such cost recovery. These included:

- that a project would bring to the grid renewable generation that would otherwise remain unavailable;
- that the area within the line's reach would play a critical role in meeting the RPS goals; and
- that the cost of the line is appropriately balanced against the certainty of the line's contribution to economically rational RPS compliance.

A proceeding is currently undergoing in order to establish the details of implementation.

5. Alberta

Alberta is part of the WECC.[64] Alberta continues to be one of the least interconnected jurisdictions in North America. Since 2002, Alberta has been a net importer of electricity.

In 1996 the Government of Alberta passed the Electric Utilities Act (Act) and each major utility applied to separate its generation, transmission and distribution costs. The framework for further restructuring of the electric utility industry was established through the Electric Utilities Amendment Act passed in 1997. In 2004, consumers were given a choice of utility retailer. Further, in 2004 the Transmission Regulation (T-Reg), which established the policies and procedures for transmission system planning, was enacted. In 2009 the Electric Statutes Amendment Act was enacted as an amendment to the Electric Utilities Amendment Act, and makes provision for Critical Transmission Infrastructure (CTI).

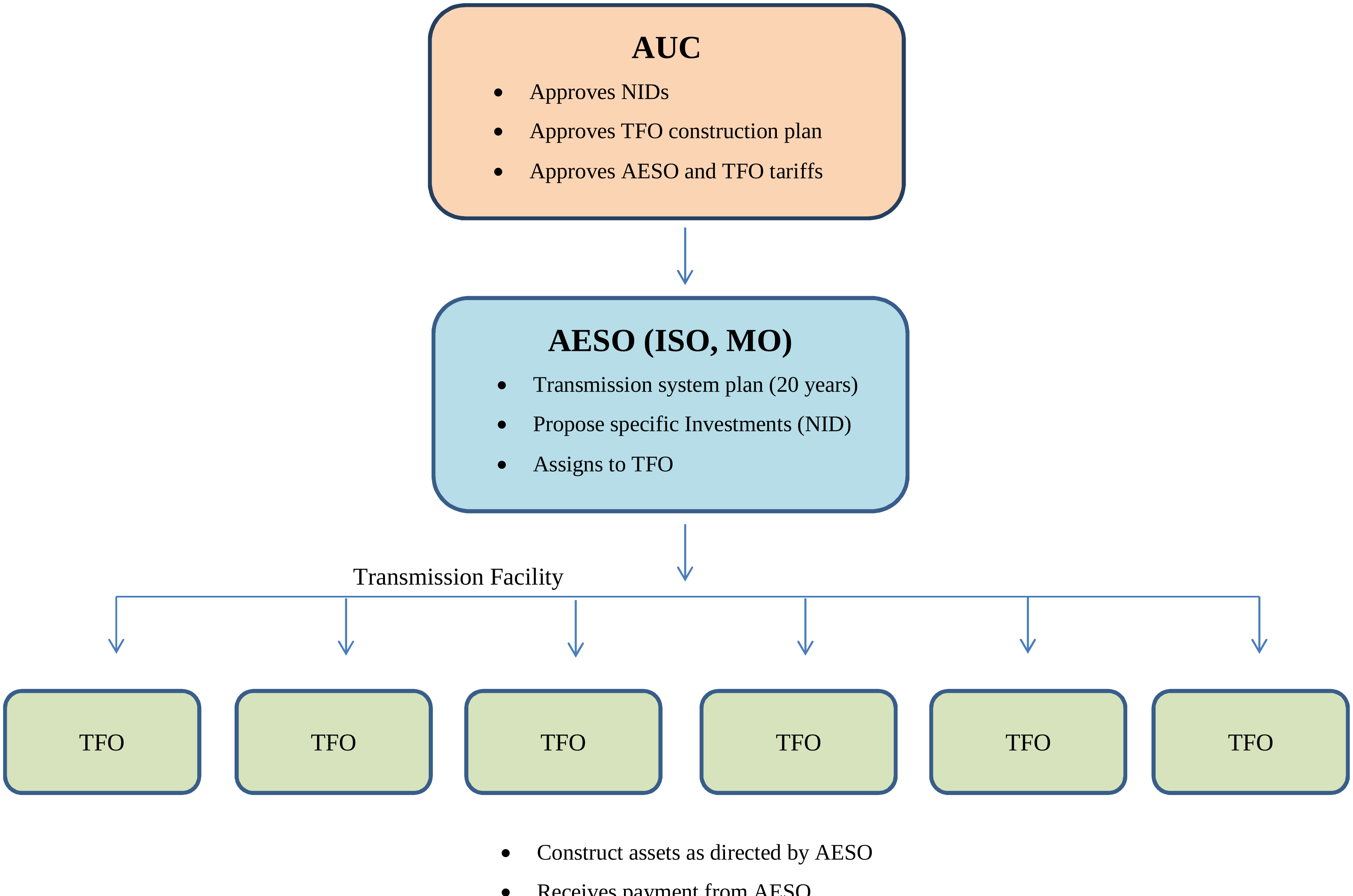
5.1. Institutional arrangements

The key institutions and entities relevant to transmission planning in Alberta are as follows:

- The Alberta Electric System Operator (AESO);
- Transmission Facility Owners (TFO)[65] and merchant transmission facilities;[66]
- The Alberta Utilities Commission (AUC);
- The Market Surveillance Administrator (MSA); and
- The Minister of Energy (ME).

64 More information on the WECC is provided at the start of Section 4 on California.
65 In Alberta transmission owners are known as 'Transmission Facility Operators'.
66 Merchant transmission facilities are intertie projects.

Figure 5.1 - Summary of Key Roles and Responsibilities - Alberta

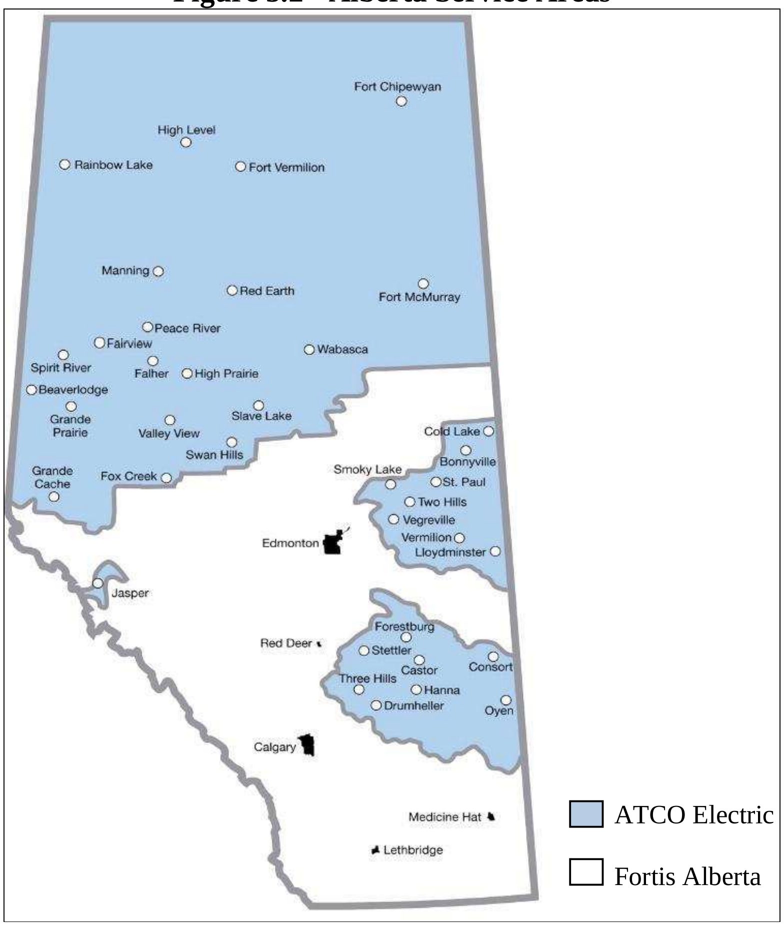


5.1.1. *Alberta Electric System Operator (AESO)*

The Alberta Electric System Operator (AESO) is the Independent System Operator in charge of planning and operating the Alberta Interconnected Electric System (AIES), facilitating competitive power markets and ensuring open access to the grid. The AIES includes all interconnected transmission facilities and electric distribution systems in Alberta except for the City of Medicine Hat.[67]

AESO is a not-for-profit entity, governed by an independent board comprised of individuals with diverse backgrounds including finance, energy management, regulatory affairs and technology. The nine Board members are appointed by the Minister of Energy.

Figure 5.2 - Alberta Service Areas



5.1.2. *Transmission Facility Owners*

There are currently six Transmission Facility Owners (TFOs) within the AIES that are eligible to apply for the construction or operation of transmission facilities. Each TFO is located in one of six distinct service areas: Fortis Alberta (where Altalink LP is the TFO), ATCO Electric, Edmonton, Calgary, Lethbridge, and Red Deer.

67 The City of Medicine Hat produces its own electricity and is connected to the grid for standby power only.

Under the T-Reg, the AESO is primarily responsible for planning and operating the transmission grid. TFOs are not responsible for any transmission system planning. However if necessary, the AESO may direct a TFO to assist in the preparation and update of its transmission plan.

Only the TFO located in the service area where a need has been identified by the AESO is eligible to construct a transmission facility. Within its service area, TFOs are responsible for building upgrades and enhancements to transmission facilities, and conducting competitive procurements for construction materials.

Once a transmission facility is constructed, a TFO is the owner of the transmission facility and is responsible for all facility maintenance.

5.1.3. *Alberta Utilities Commission*

The Alberta Utilities Commission (AUC) regulates all investor-owned electric utilities and certain municipally owned electric utilities. This includes all of the six TFOs in the AIES. The AUC also regulates the tariffs charged by AESO and the TFOs.

The AUC does not approve the overall transmission plan prepared by the AESO. However the AUC is responsible for approving specific transmission projects identified by the AESO as part of its transmission system plan, and proposed to the AUC in a Needs Identification Document (NID) (see section 5.3).

5.1.4. *Market Surveillance Administrator (MSA)*

The Market Surveillance Administrator (MSA) is appointed by the Minister of Energy for a five year term. The MSA reports to the Minister annually on compliance in regards to the ISO Rules and Alberta Reliability Standards by the AESO, TFOs, Distribution Facilities Operators and other market participants.

The AESO and MSA work closely together to address compliance with the ISO rules. The AESO, which is responsible for monitoring compliance with the ISO rules, must refer a matter of non-compliance to the MSA. The MSA follows the AUC’s rules regarding penalties but does not need Commission approval to issue a penalty to the AESO or any market participant for non-compliance.

5.1.5. *Minister of Energy*

The Minister of Energy (ME) leads the Energy Department of the Government of Alberta. The ME is appointed by the Premier of Alberta who also issues a mandate letter annually identifying key initiatives to be accomplished each year. Specifically, the Energy Department sets policies to manage the development of the province's non-renewable resources, grant industry the right to explore for and develop energy resources, establish, administer and monitor the effectiveness of fiscal and royalty systems, promote energy efficiency and conservation, and encourage additional investment that creates jobs and economic prosperity.

The ME is responsible for appointing members of the AESO’s Board and the MSA. Additionally, the ME has the power to make regulations limiting or restricting the powers, duties, or responsibilities of the AESO.

Under the Electric Statutes Amendment Act, the ME is responsible for approving the need for Critical Transmission Infrastructure (CTI) that has been designated by the Lieutenant Governor to meet Alberta's electricity needs.

CTI is defined in the Electric Statutes Amendment Act as a transmission facilities project that is:

- an intertie;[68]
- to serve areas of renewable energy;
- a double circuit transmission facility that is designed to be energized at a nominal voltage of 240 kV,
- designed to be energized at a voltage in excess of 240 kV, or
- in the opinion of the Lieutenant Governor in Council, critical to ensure the safe, reliable and economic operation of the interconnected electric system.

All other transmission infrastructure projects are approved by the AUC.

5.2. Planning process

The T-Reg establishes the policies and procedures for transmission system planning, and defines the role of the AESO, AUC, and TFOs.

Under the Act, the AESO is responsible for forecasting the generation and transmission needs of Alberta, preparing and maintaining a 20-year system plan for the AIES, and developing and administering the AESO transmission tariff. The AESO may delegate any or all of these tasks to the TFOs, but has not done so to date.

The AUC oversees the design of the transmission system by approving investment needs identified by the AESO in its NID and construction projects proposed by TFOs.

5.2.1. *Market-wide planning*

The T-Reg requires the AESO to prepare and maintain a Long-Term Transmission Plan (Plan) that spans a 20 year horizon. The Plan must be updated every two years but may be updated more often at the discretion of the AESO. If necessary, the AESO may direct a TFO to assist in the preparation and update of the plan. The Plan is made public on the AESO website and does not have to be formally approved by the AUC.

Specifically the Plan projects:

- the forecast load on the interconnected electric system (ie, the AIES), including exports to neighbouring systems;
- the anticipated generation capacity, including reserves and imports of electricity from neighbouring systems;
- the timing and location of future generation additions, including areas of renewable or low emission generation;

[68] An intertie is a transmission facility that links one or more electric systems from outside Alberta to one or more points on the AIES

- the transmission facilities required to meet the forecast load, imports and exports of electricity and anticipated generation capacity, including appropriate reserves and facilities to serve areas of renewable or low emission generation, in a timely and efficient way;
- the transmission facilities required to provide for the efficient and reliable access to neighbouring regions and
- other matters the AESO considers appropriate.[69]

In addition to forecasting load growth and generation development, when updating the Plan the AESO will also take into consideration factors such as government policies, technological advances, and environmental impacts. The Plan must also address criteria related to the communications required for transmitting teleprotection signals, operational data, and radio communications; and certain market and operational products and services such as ancillary services and congestion management used to support the operation of the system.

5.2.1.1. *Load and Generation Forecast Process*

The AESO is responsible for updating the load and generation forecasts to be included in the Plan. The T-Reg allows for this responsibility to be delegated to TFOs by the AESO, but this has not been done in practice. The AESO uses the load forecast information to identify future transmission facility needs and the generation forecast to anticipate any additional generation capacity required to meet the forecast load.

When forecasting load, the AESO first identifies the key economic variables driving demand, which have previously included the Alberta gross domestic product, population growth, oilsands production[70], personal disposable income, and project and distribution facility owner future load estimates. These variables are used in econometric, top-down, and bottom-up models. Next, using all electricity loads connected to the transmission system, including behind-the-fence load[71], the AESO forecasts load for each customer sector, identified by a distinct factor driving demand. Representative load shapes for points of delivery on the transmission system are then used to create realistic hourly loads and to forecast seasonal peaks. Finally, the model is tested for robustness in the short term in order to validate the model and inputs. Short-term uncertainties, such as project timing and start-up rates, and long-term uncertainties, such as project development and new technologies, are assessed.

Once the load forecast is complete, AESO will create a generation forecast by reviewing annual generation capacity additions by location, resource type and size, and determine if there are supply gaps between load growth and future generation retirements. Additionally, AESO will also consider short-term and long-term drivers and uncertainties affecting generation development, including available technologies, current policies, fuel and capital costs, and operating characteristics. By reviewing the current generation queue and project list, using market simulations, and holding discussions with customers and industry representatives, AESO will validate the forecast.

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[69] AR 86/2007 s10

[70] A major industry in Alberta.

[71] These are projects that involve work to an existing industrial load or generation site and require no physical change to the transmission connection.
See: http://www.aeso.ca/market/17899.html

5.2.1.2. *Localised Planning*

To access transmission needs on a localised level, AESO divides the AIES into five regions that are differentiated based on distinctive load and generation characteristics. A thorough review of the needs of each region is then done down to a 69 kV level. The load and generation forecasts are used in transmission planning models to create base case models, scenarios, sensitivities and to stress test cases by region. The ability of the system to move power between the regions is also tested.

The T-Reg requires the transmission system to operate without interruption when all transmission facilities are in service, and at 95 per cent when operating under abnormal conditions. Additionally, in order to comply with the Alberta Reliability Standards, the AESO must demonstrate that the transmission system is planned in a 10-year horizon so that: the system can be operated to: (i) accommodate the load and generation capacity forecasts without interruption when all facilities are in service and when one element is lost; (ii) accommodate forecast load with controlled load interruption or removal of generation following the loss of two or more elements. The AESO must also test operability in extreme events.[72]

The system is tested in the short-term (one to five years) and long-term (six to ten years) by adding and removing proposed transmission enhancements and projects in order to identify future problems and determine appropriate timing of enhancements.

5.3. Investment decision roles and responsibilities

AESO must identify in the Plan all transmission facility projects that will be proposed to the AUC within five years of the date of the Plan, and provide an implementation schedule for each proposed project.

The investment decision making and transmission facilities construction procedures are discussed below.

5.3.1. *Investment decision making*

AESO evaluates the needs for investment or upgrades in the Plan over three key periods:

- short term (two-year horizon), typically focused on regional needs;
- medium term (10-year horizon) identifying medium-term needs, addressing the bulk power system and regional needs; and
- long-term (up to a 20-year timeline) indicating long-term developments, typically aimed at bulk system enhancements that link regional developments.

The responsibilities for investment decisions are set out in the Act.

AESO is responsible for determining when a transmission facility project is needed and evaluating investment options. Transmission facility projects that the AESO proposes for construction within the next five years are identified in the Plan. In relation to any specific investments identified in the plan, the procedure for the approval of each investment begins with AESO submitting a Needs Identification Document (NID) for approval by the AUC.

72 2011 Long-Term Transmission Plan

The NID must include a technical and economic comparison of all options considered by AESO in order to meet a particular need. The T-Reg requires that each investment option is evaluated for the following:

- impact on generation must-run requirements;
- impact on the transmission system plan;
- operational efficiency and reliability, and improvements added to the system;
- ability to meet reliability standards and system capability;
- proposed transmission substation and line configurations;
- timing and risk during construction; and
- environmental and other considerations.

When the AESO has evaluated more than one option, the NID will identify the preferred option and the rationale for selecting this option over the alternatives.

Prior to submitting the NID, the AUC requires the AESO to conduct public consultation and notify all occupants and landowners in the area of the proposed transmission lines or substations. Additionally, the AESO should include all industry stakeholders in proceedings.

When evaluating the NID the AUC will consider whether the proposed project improves system reliability, contributes to a robust competitive market, provides a market benefit, such as a reduction in losses, a deferral of generation investment or a reduction in dispatch costs, and maintains options for long term development. Where the proposal is for an intertie, the AUC must consider if the project provides system access service.

The AUC will hold a public hearing process to allow affected parties the chance to give their opinion to the AUC panel directly. The AUC will assume the AESO's assessment of the need for the investment is correct, unless a market participant proves to the AUC that the need identified by the AESO is technically deficient or is not in the public interest.[73] Within 90 days of the close of the hearing AUC will issue a decision on the proposed project in the form of a written report. Involved parties will receive the report directly from the AUC. The AUC posts all reports on their website.

5.3.2. *Detailed design, procurement and construction*

Once a NID has been approved by the AUC, the AESO will assign the project to the eligible TFO within the service area. The TFO will then file an application with the AUC for approval of the construction, connection and operation of a new transmission facility within the province.

Prior to submitting an application with the AUC, the TFO must evaluate alternative transmission routes or substation locations and examine factors such as land ownership, existing development, wildlife and historic resources. The TFO must also conduct public consultation prior to submitting an application. The TFO must discuss with affected parties their construction plans and routes, safety precautions for nearby residents, the expected lifespan of the completed facility, and impacts residents can expect on the land.

[73] AR 86/2007 s19;255/2007

The AUC will hold a public hearing and issue a written report including a synopsis of the AUC's findings and the final decision.

In accordance with the Act, the AESO has issued procurement rules for project construction, provided as section 9 to the ISO Market Rules. These rules have been approved by the AUC and must be followed by the TFO's in constructing the project.

Specifically, when a project's materials cost, as estimated by the TFO, exceeds $50,000, the TFO must solicit written bids from no less than three independent suppliers. If a project's cost is estimated to cost between $10,000 and $50,000, the TFO must solicit short form written bids from no less than three independent suppliers. The TFO must award the contract to the supplier with the lowest cost, compliant bid, unless it can demonstrate to AESO that it was commercially reasonable to accept a higher cost bid. A TFO can contract with a supplier for construction of a transmission facility without soliciting bids if there is only one entity capable of providing the needed service or if there was not enough time to solicit bids.

The AESO will monitor the construction process and can require monthly reports from the TFO for projects estimated to cost more than one million dollars. AESO must be kept abreast if the project is experiencing construction delays or if the forecast cost is expected to vary by more than 10% from the amount specified by the AESO. To allow for a transparent process, the AESO posts project reports to its website quarterly

5.4. Economic regulation arrangements

5.4.1. *Cost recovery for TFOs*

TFOs are entitled to recover the costs of transmission investments in an AESO tariff. This tariff is approved by the AUC (provided that the AUC considers it to be prudent and reasonable), and is charged to all transmission customers.

The Act identifies the costs that a TFO can recover from the AESO in its tariff, if the AUC has approved both the AESO's NID and the TFO's application for construction of the project facility. These costs include (i) pre-construction costs (such as feasibility studies, engineering, equipment and materials, and land purchases); (ii) costs incurred when assisting AESO in preparing the transmission system plan or NID; (iii) construction costs; and (iv) any additional costs related to meeting reliability standards.

5.4.2. *Cost Recovery for AESO*

AESO levies the AESO tariff on all wholesale electricity consumers using the transmission network. The share of the AESO tariff-related revenues corresponding to the load of the end-use customers is recovered through the rates they pay for their electricity service. Customers choose whether to continue receiving electricity from a retailer that is regulated by the AUC or from a competitive retailer. A retailer regulated by the AUC is called the regulated rate option (RRO). Each customer receives a bill from either the RRO or a competitive retailer. All customers see unbundled generation, transmission, and distribution charges. The transmission charge is determined by the AESO tariff. Transmission costs are recovered by all customers based on their use of the transmission system.

The AUC will review the TFO's tariff and will determine if the costs are prudent and reasonable. The AESO files a tariff application with the AUC annually. The prices and rates are set in a two-step process. The Phase I application will set the AESO's revenue requirement which includes costs related to the use of the transmission network, ancillary services, transmission line losses, and the AESO's administration. The Phase II application determines the allocation of costs between customer classes and sets rates charged to customers. The transmission network costs included in AESO's tariff application are a pass-through to the TFOs.

5.4.3. *Connection costs and generation incentives*

The AESO defines local connection[74] costs in its ISO tariff, which are payable by the generating asset owner in exchange for connecting to the transmission system. Generation asset owners pay a System Contribution calculated as the sum of the Base Contribution (set equal to $10,000/MW for upgrades to existing transmission facilities) and the Regional Contribution of $0/MW to $40,000/MW, depending on if the generating unit is located in an area of the transmission system where generation already exceeds load. The contribution is paid back over a period of no more than ten years from the date the unit began generating energy for exchange. The generating asset must satisfy the following three criteria in order to receive a refund annually:

1. The generating asset is commercially operational prior to the first year of the refund period, or has been maintained operational for each year of the refund period.
2. The asset's average capacity factor has met or exceeded required levels that are provided by generating unit type.
3. The generating asset's metered demand has not exceeding 110% of the supply transmission service capacity, set in a service agreement, at any point during the calendar year.

5.5. Reliability standards

The ARS is proposed by the AESO and is subject to approval by the AUC.

The Act requires the AESO to propose the standards of either the WECC or NERC. Before filing reliability standards with the AUC for approval, the AESO will hold a public consultation, respond to stakeholder submissions and submit the proposal for internal AESO executive approval. The AUC will set the effective date of a reliability standard.

An independent Market Surveillance Administrator (MSA) reports on compliance in regards to reliability standards by the AESO, TFOs, Distribution Facilities Operators (DFOs) and other market participants. At the same time, the AESO is responsible for ensuring that market participants including TFOs adhere to reliability standards and the ISO Rules. If AESO suspects non-compliance, it must defer to the MSA for possible enforcement action. Additionally, AESO is subject to a penalty for non-compliance with reliability standards. If the AESO self-discloses non-compliance, the applicable penalty will be reduced by twenty-five per cent.

The MSA can issue notices of penalty without approval from the AUC; however, participants have the ability to dispute such penalties before the AUC. A penalty or sanction that is issued

[74] In the US and Canada, the term 'interconnection' is used to refer what in Australia is called the 'connection' of generators and load.

to AESO can in turn be recovered by AESO from a market participant, if AESO can demonstrate that the market participant was the cause of non-compliance.

5.6. Recent developments

In accordance with the T-Reg, the AESO filed a proposal with the AUC on September 15, 2011 to establish a competitive process that would determine who is eligible to apply for the construction and/or operation of certain transmission facilities.[75] Specifically, the proposed process will be used for Critical Transmission Infrastructure (CTI) only. The Lieutenant Governor can designate a project from the AESO Plan as CTI.

Under the proposed process, incumbent TFOs and new market entrants would bid on all activities in the full life cycle of an asset including upfront activities, engineering, procurement, construction, ownership and operation and maintenance. The successful entity would be responsible for all project activities including the ownership, operation and maintenance of the facilities. Costs resulting from the competitive process would require approval from AUC, and any approved project costs would be recovered in AESO’s ISO tariff.

AESO stated the following objectives for the competitive process:

- must result in the minimization of life-cycle costs through the use of competitive pricing;
- must create opportunity for maximum innovation throughout the life cycle of the facilities;
- must create opportunity for new market entry;
- must allocate risk to most efficiently and effectively reduce costs and mitigate risk;
- must foster efficient investment, operation and maintenance of assets across the life cycle of the facilities;
- must foster regulatory predictability;
- must be straightforward and efficient;
- must clearly state the accountabilities of each party involved;
- must achieve a reasonable level of transparency and consistency over time;
- must ensure the facilities are designed to meet standards for performance and reliability and do not jeopardize the Alberta interconnected electric system;
- must be fair, open and consultative;
- must consider obligations typically assumed by the incumbent transmission facility owner; and
- must provide transparent selection criteria to address the principles outlined above.

75 AR 153/2010 s18

The AUC is expected to decide on the proposal in June 2012.

Additionally, the Government of Alberta plans to introduce legislation in the Fall of 2012 to give the AUC the authority to approve future needs and routing of all transmission facility projects including CTI.

6. FERC Order 1000

6.1. Background and overview of FERC Order No. 1000

On July 21, 2011, the U.S. Federal Energy Regulatory Commission (FERC) issued Order 1000, ‘Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities’. Order No. 1000 mandates a number of reforms, revolving around the establishment of a regional transmission planning process, interregional transmission coordination requirements, elimination of the federal right of first refusal, and the issuance of cost allocation guidelines.

In 2006, following on the adoption of the 2005 Energy Policy Act, FERC initiated a rulemaking in order to implement needed revisions to the Open Access Transmission Tariffs (OATTs)[76] and to correct any loopholes and shortcomings in FERC’s previous orders. That rulemaking process culminated in the issuance of FERC’s Order No. 890 in December of 2007. Order No. 890 provided greater specificity intended to reduce opportunities for undue discrimination and facilitate enforcement of FERC's authority in transmission planning.

In Order No. 890, the Commission required neighbouring public utility transmission providers to share information on system plans and identify system enhancements that could relieve congestion or integrate new resources, as well as to respond to explicit stakeholder requests for studies of potential system upgrades, in the context of evaluating local transmission plans.

Order No. 890 did not require transmission providers to proactively identify potential region-wide solutions to meet the region's transmission needs, or to evaluate potential regional upgrades in the absence of stakeholder requests. Industry stakeholders continued highlighting remaining deficiencies embedded in FERC Order No 890 with respect to transmission planning processes and cost allocation methods. As a result, on June 17, 2010, FERC issued a Notice of Proposed Rulemaking (NOPR) seeking comment on potential changes to its transmission planning and cost allocation requirements. Industry participants and other stakeholders provided extensive comments in response to the NOPR, which led to the development of FERC Order 1000.

Order No. 1000 became effective October 10, 2011, and its planning and cost allocation principles apply only to *new* transmission facilities. New transmission facilities are those subject to evaluation or re-evaluation within a local or regional transmission planning process after the effective date of the relevant public utility transmission provider’s filing adopting the relevant requirements of Order No. 1000.

[76] In 1996, FERC Order No 888 required all public utilities that own electricity transmission to provide open access transmission service on a comparable basis to the transmission service they provided to themselves. This led to the development of OATT, which permits public utilities to seek recovery of legitimate costs associated with providing open access, transmission service and ancillary services, and contains information about the general procedures to provide these services as well as minimum terms and conditions of non-discriminatory service.

6.2. Provisions relating to transmission planning

The Order builds on the reforms of Order 890 with respect to transmission planning processes and cost allocation methods, and includes both regional and interregional provisions. The main elements of FERC Order 1000 regarding transmission planning are discussed below.

6.2.1. *Regional Planning Process*

Each public utility transmission provider[77] will be required to participate in a regional transmission planning process, such as the regional planning process run by PJM or CAISO. Both the individual local transmission plans and the regional plans will consider and evaluate transmission and non-transmission solutions that may have been proposed to create a plan that meets the needs of transmission customers and other stakeholders.

Merchant transmission project developers need not participate in the regional planning process for purposes of determining the allocation of transmission costs. However, they must provide information to the public utility transmission providers in the region so that they can assess the potential reliability and operational impacts of the proposed transmission facilities on other systems in the region. Merchant transmission providers are also responsible for the cost of network upgrades that are caused by the interconnection of their projects with the grid. Merchant transmission providers are distinct from traditional public utility transmission providers in that they assume the entire risk of a project and must recover the costs of constructing the proposed transmission facilities through market based rates (instead of cost-based rates).

6.2.2. *Interregional Planning Process*

Each public utility transmission provider is now required to coordinate with neighboring transmission planning regions and create an interregional transmission planning *agreement*. This means that neighboring regions must develop and implement procedures for the joint evaluation and sharing of information of potential transmission projects that *span multiple regions*, to facilitate interregional planning. Projects that span multiple regions include those assets that are expected to be located in more than one region.[78]

The Commission requires that the planning process identifies the consequences of a project that is located in only one region for other regions, including upgrades that may be required. However a region can allocate costs solely within the region unless another region agrees to assume a portion of the costs. The Order does not intend to mandate interconnection-wide planning, but FERC stated that it believes that the exchange of data and information will assist planners in understanding the interregional impacts of facilities that are located in only one region. The Commission noted that transmission providers may voluntarily agree to accept an allocation of costs of a project in another region if the project has benefits to them. The Commission held that allowing involuntary cost allocations between regions would place

77 This includes Independent System Operators (ISOs), Regional Transmission Organisations (RTOs), and also any public utility owning transmission assets that recovers the costs of transmission in FERC-approved cost-based rates. It excludes municipal utilities and electric cooperatives, although FERC expects that these will voluntarily participate in the regional planning processes.

78 Note that a project which could meet a reliability need in region B but which us located solely in region A would not be captured as part of this interregional planning process.

too high a burden on stakeholders to monitor transmission planning processes in other regions.

Order No. 1000 does not require the development of separate interregional transmission plans. RTOs are not required to establish a distinct interregional transmission planning process, separate from the regional transmission plan. Rather, FERC requires public utility transmission providers to consider whether the local and regional transmission planning processes result in transmission plans that meet local and regional transmission needs efficiently and cost-effectively, after considering opportunities for collaborating with public utility transmission providers in neighboring transmission planning regions. The goal is to identify joint interregional transmission facilities that address transmission needs efficiently and cost-effectively.

In addition, Order No. 1000 requires that public utility transmission providers amend their Open Access Transmission Tariffs (OATTs)[79] to include procedures for the identification of transmission needs driven by public policy requirements established under state or federal law, and the evaluation of solutions to meet those needs.

6.2.3. *Right of First Refusal*

Other elements affecting transmission planning concern the planning role of incumbent transmission developers. In some regions, incumbent transmission owners had a "Right Of First Refusal" to build transmission facilities. FERC stated that this created opportunities for undue discrimination and preferential treatment for transmission owners, putting non-incumbent transmission developers at a disadvantage. FERC directed all public utilities to revise their OATT to remove any right of first refusal provisions and create ways for non-incumbent developers to participate in transmission planning and submit project proposals.

To implement the elimination of right of first refusal provisions, FERC has adopted a new framework for evaluating transmission proposals. Under Order No. 1000 transmission providers are required to revise their OATTs to (i) demonstrate that the regional planning process has appropriate, non-discriminatory qualification criteria; (ii) identify the information that must be submitted by prospective transmission developers, and the date by which such information must be submitted; and (iii) include a description of a transparent and non-discriminatory evaluation process for the selection of proposed transmission facilities for purposes of cost allocation.

6.2.4. *Cost allocation*

FERC Order 1000 states that each public utility transmission provider must have in place a common method for allocating the costs of new transmission facilities selected in the regional transmission plan in which they participate for purposes of cost allocation. Transmission providers must revise their OATTs to describe a transparent and not unduly discriminatory process for deciding whether to include a proposed transmission facility in a regional plan for purposes of cost allocation. In addition, any two neighboring transmission planning regions

[79] In 1996, FERC Order No 888 required all public utilities that own electricity transmission to provide open access transmission service on a comparable basis to the transmission service they provided to themselves. This led to the development of OATT, which permits public utilities to seek recovery of legitimate costs associated with providing open access, transmission service and ancillary services, and contains information about the general procedures to provide these services as well as minimum terms and conditions of non-discriminatory service.

must have a common interregional cost allocation method for new interregional transmission facilities. A particular region may have different regional and interregional cost allocation methods.

Although FERC is allowing each region to develop its own cost allocation method, the Order requires that the cost allocation methodology chosen for a particular facility bears some relationship to the planning criteria for that facility. In particular, each regional cost allocation method must meet six cost allocation principles for regional or interregional projects. These principles are summarized below.

1) The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.

2) Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities.

3) If a cost-benefit test is used to evaluate the need for new facilities, the benefit-to-cost ratio cannot exceed 1.25 unless the region makes a showing to justify a higher ratio.

4) The allocation method for the cost of a transmission facility selected in a regional transmission plan must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs.

5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

6) A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional transmission plan, such as transmission facilities needed for reliability, congestion relief or to satisfy public policy requirements.

The interregional cost allocation methodology may be different from the respective regional methodologies. In other words, the cost allocation for a region's share of an "interregional facility" may differ from the cost allocation for a "regional facility". In addition, "Participant funding" will not be acceptable by FERC as the interregional cost allocation methodology.

The Order notes that the state regulatory commissions should have a role in determining how to allocate the costs of facilities that are intended to address public policy requirements and encouraged them to participate actively in this issue.

FERC has backstop cost allocation authority, meaning that, in the event a region cannot agree on the interregional cost allocation method, FERC will make a determination based on the record in the relevant compliance proceedings.

6.3. Compliance requirements for RTOs

The Order has a two-part compliance filing requirement for all Public Utility Transmission Providers.

- October 11, 2012 – Compliance Filing Deadline for Regional Provisions: Public Utility Transmission Providers must modify their OATTs to comply with the Order's new regional planning requirements and cost allocation requirements, as discussed below.

- April 11, 2013 – Compliance Filing Deadline for Interregional Provisions: Public Utility Transmission Providers must modify their OATTs to be compliant with the Order's interregional transmission planning/coordination. Interregional planning/coordination could involve pairs of regions (bi-lateral), several regions (multi-lateral) or all regions (Interconnection-wide). Simultaneous Interconnection-wide planning is not required by the Order.

Broadly speaking, the regional provisions of FERC Order 1000 will likely not compel any of the existing ISOs/RTOs to dramatically change their planning activities *within* the region. Most regions served by an RTO/ISO have cost allocation methodologies that address many of the principles contained in the Final Rule. It is therefore reasonable to expect that, in many regions served by ISO/RTOs, there only will be incremental changes to existing cost allocation methodologies (*e.g.*, to include public policy driven projects).

However, regarding *interregional* planning and cost allocation methods, it is likely that all regions will face some compliance challenges with this aspect of the Order. Currently all ISO/RTOs are beginning to hold technical conferences to review the changes they will need to implement related to implementing the provisions relating to *interregional* planning/coordination.

A number of aspects of the Order will need to be further developed. For example, the cost of an interregional project is not eligible for cost sharing unless *both* regions agree to include it in their individual regional plan. FERC is requesting that a joint evaluation of an interregional transmission facility for purposes of determining cost allocation, takes place in the same time frame as the regional planning process. However this parallel evaluation may prove difficult if a developer first must propose and get its transmission project accepted in each of the neighboring regions in which the facility is going to be located. In addition, if the project is intended to transmit renewable energy to a distant load center in another region, the region where the renewable resources are located may be reluctant to select the project for regional cost allocation unless the receiving regions agree in advance to pay for a share of the cost of those projects.

Some of the immediate compliance implications are as follows:

- Cost allocation principles place strong emphasis on assessments of costs and benefits, and allocation of costs to beneficiaries. The FERC Order 1000 requirement will likely increase the level of scrutiny on planning decision making, particularly in non-RTO territories.
- In a non-RTO/ISO transmission planning region, each public utility transmission provider located within the region must set forth in its OATT the same language regarding the cost allocation method or methods used in its transmission planning region. Transmission

planners in non-ISO areas may face challenges in determining what constitutes a "regional" planning footprint versus an "interregional" planning footprint.

- Information Sharing – Transmission providers must share and use consistent planning information (e.g., data, assumptions, results).
- Documentation – Regional planning must have sufficient documentation of costs and benefits, and transparency to support cost allocation, including by FERC, under its new backstop authority.
- Non-Transmission Alternatives: As scrutiny of planning increases, the need to increase the amount of consideration given to alternatives to transmission will likely increase. In some regions, this means increased focus on demand resources, location of transmission-connected generation units, distributed generation, and other alternatives to proposed reliability and other transmission system upgrades.
- Stakeholder Input – Regional transmission planning must have adequate stakeholder input and transparency.

6.4. Expected impact on RTOs/ISO and non-RTOs

At the moment, all RTOs are carrying out meetings to discuss the changes that they need to implement and to develop compliance filings addressing the interregional planning and cost allocation requirements of Order No. 1000.

PJM and MISO already have FERC-approved interregional cost allocation methodologies that in principle address cost allocation of interregional projects in the manner contemplated in the Order. However the NYISO, ISO-NE and the CAISO expansion and cost allocation process will need to be modified to include interregional cost allocation considerations.[80]

The core elements of the current discussions of these RTOs are highlighted below.

- NYISO, PJM and ISO-NE are currently identifying inter-regional issues in the context of the existing "Northeastern ISO/RTO Planning Coordination Protocol" that will need to be modified to comply with FERC Order 1000. The lines of action identified so far include:
    - Develop procedures for joint evaluation and information sharing regarding transmission needs or neighbouring regions and potential interregional solutions.
    - Develop procedures to identify whether interregional facilities are more efficient or cost-effective than regional solutions and determine necessary transmission studies when evaluating conditions on neighbouring systems.
    - Mandate that interregional transmission projects must first be proposed in the regional transmission planning processes of each of the neighbouring regions in which the facility is proposed to be located.
    - Monitor environmental regulations and their impact on interregional system performance, identify issues and solutions to facilitating integration of renewable resources, and study the effect of demand-side resources on interregional planning.

[80] Note that Alberta does not need to need to comply with FERC 1000.

- The CAISO's current competitive solicitation process is aligned with the Order No. 1000 requirements. However there are two areas that the CAISO will clearly need to work on to comply with FERC Order 1000, as follows:

  - Eliminate existing tariff provisions that give PTOs the right of first refusal[81] to build reliability projects that are high voltage (greater than 200 kV) facilities in the ISO's transmission plan (except with regard to upgrades of the PTOs' own facilities), regardless of whether these projects provide additional policy-driven or economic benefits.

  - Coordinate cost allocation provisions with all neighbouring regional planning entities. The CAISO's current transmission planning process provides an opportunity for interconnected neighbours to exchange planning information and objectives and the CAISO also participates in the activities of the CTPG, a planning group that encompasses most of the balancing area authorities in California and therefore coordinates with neighboring systems to explore possibilities of cooperation and assess feasibility of their respective plans. However there is not a binding requirement embedded in this coordination efforts or a specific requirement to use a common cost allocation method. A significant effort will be required to develop the additional procedures for determining common cost allocation methods for interregional facilities.

Both PJM and NYISO will both have to amend their Transmission Tariffs as a consequence of FERC 1000 to ensure that the incumbent transmission provider does not have the Right of First Refusal over new transmission projects selected in a regional transmission plan. However, we note that this does not necessarily mean that they will establish a competitive solicitation process akin to that adopted in California. Rather, they will simply need to make sure that all transmission proposals get the same treatment and that the incumbent TO only has priority to construct local transmission projects that are not part of the regional cost allocation process and are all within its service territory, and for upgrades to existing transmission facilities.

[81] Under the CAISO tariff, incumbent PTOs have a right of first refusal, ie, the exclusive right to build and own, high voltage (greater than 200 kV) transmission projects that are required for reliability reasons within its service territory, as well as any upgrades of the PTOs' own facilities. Projects that are required to meet policy goals or that provide economic benefits remain subject to CAISO's competitive solicitation process.

Glossary

AB	Assembly Bill
AEMC	Australian Energy Market Commission
AESO	Alberta Electric System Operator
AIES	Alberta Interconnected Electric System
ARR	Auction Revenue Rights
ARS	Alberta Reliability Standards
ATC	American Transmission Company
AUC	Alberta Utilities Commission
BA	Balancing Authority
BES	Bulk Electricity System
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CARIS	Congestion Analysis and Resource Integration Studies
CEC	California Energy Commission
CEQA	California Environmental Quality Act
ConEd	Consolidated Edison
CPCN	Certification of Public Necessity and Convenience
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zones
CRP	Comprehensive Reliability Plan
CRR	Congestion Revenue Right
CRRP	Comprehensive Reliability Planning Process
CSSP	Comprehensive System Planning Process
CTI	Critical Transmission Infrastructure
CTPG	California Transmission Planning Group

DSR	Demand Side Response
EE	Energy Efficiency
EIPC	Eastern Interconnection Planning Collaborative
ERO	Electricity Reliability Organisation
ESPWG	Electric System Planning Working Group
FERC	Federal Energy Regulatory Committee
FSA	Facilities Study Agreement
FTR	Financial Transmission Right
IMO	Independent Market Operator
IOU	Investor Owned Utilities
IRAG	Interconnection Reliability Assessment Group
IRP	Integrated Resource Plan
ISA	Interconnection Service Agreement
ISO	Independent System Operator
ISO-NE	Independent System Operator – Northeastern
LADWP	Los Angeles Department of Water and Power
LCRI	Location Constrained Resources Interconnection
LCRIF	Location Constrained Interconnection Resource Facility
LCTS	Local Capacity Technical Study
LIPA	Long Island Power Authority
LLC	Limited Liability Company
LM	Load Management
LMP	Locational Marginal Price
LOLE	Loss Of Load Expectation
LTPP	Local Transmission Owner Planning Process
LSE	Load-Serving Entity

LTPP	Long Term Procurement Process
ME	Minister of Energy
MISO	Midwest Independent System Operator
MO	Market Operator
MSA	Market Surveillance Administrator
NEM	Australian National Electricity Market
NERA	NERA Economic Consulting
NERC	North American Reliability Council
New York State PSC	New York State Public Service Commission
NID	Needs Identification Document
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSEG	New York State Electricity Group
NYSRC	New York State Reliability Council
OATT	Open Access Transmission Tariff
PC	Planning Committee
PG&E	Pacific Gas & Electric
PJM	Pennsylvania-Jersey-Maryland
PPA	Power Purchase Agreement
PTC	Permit to Construct
PTO	Participant Transmission Owners
PUC	States Public Utility Commission
PU Code	Public Utility Codes
RBB	Registered Ballot Body
RETI	Renewable Energy Transmission Initiative

RNA	Reliability Needs Assessment
RPS	Renewables Portfolio Standard
RRO	Regulated Rate Option
RPPWG	Regional Planning Process Working Group
RTEP	Regional Transmission Expansion Planning
RTO	Regional Transmission Organisation
RTPP	Revised Transmission Planning Process
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SERC	Southeastern Electric Reliability Council
SMUD	Sacramento Municipal Utility District
SPP	Southwest Power Pool
SRRTEP	Sub Regional Regional Transmission Expansion Planning
SUF	System Upgrade Facility
TAC	Transmission Access Charge
TCA	Transmission Control Agreement
TEAC	Transmission Expansion Advisory Committee
TFO	Transmission Facility Operator
TLA	Transmission Load Area
TO	Transmission Owners
TPAS	Transmission Planning Advisory Subcommittee
TPP	Transmission Planning Process
TTC	Total Transmission Capability
TVA	Tennessee Valley Authority
WECC	Western Electricity Coordinating Council

Appendix A. Required Characteristics and Functions of Regional Transmission Organisation

According to FERC, RTOs are designed to "promote efficiency in wholesale electricity markets and ensure that electricity consumers pay the lowest price possible for reliable service."

FERC has four required characteristics and eight required functions for an entity to be an RTO.

The four required characteristics are:

1. *Independence*: the RTO must be independent of any market participant.
2. *Scope and regional configuration*: the RTO must serve an appropriate region.
3. *Operational authority*: the RTO must have operational authority for all transmission under its control.
4. *Short-term reliability*: the RTO must have exclusive authority for maintaining the short-term reliability of the grid it operates.

The eight functions of an RTO are:

1. *Tariff administration and design*: the RTO must administer its own transmission tariff and employ transmission pricing that promotes efficient use and expansion of transmission and generation.
2. *Congestion management*: the RTO must develop and operate market mechanisms to manage transmission congestion.
3. *Parallel path flow*: the RTO must develop and implement procedures to address parallel path flows within its region and with other regions.
4. *Ancillary services*: the RTO must serve as a provider of last resort of all ancillary services required by FERC Order 888 and subsequent orders.
5. *OASIS, Total Transmission Capability (TTC) and Available Transmission Capability (ATC)*: the RTO must be the single OASIS site administrator for all transmission facilities under its control and independently calculate TTC and ATC.
6. *Market monitoring*: the RTO must provide objective monitoring of the markets it operates to identify market design flaws, market power abuses and opportunities for efficiency improvements, and propose appropriate actions.
7. *Planning and expansion*: the RTO must be responsible for planning and directing needed transmission expansions, additions and upgrades that enable it to provide efficient, reliable and non-discriminatory transmission service, coordinating its planning with appropriate state agencies.
8. *Interregional coordination*: the RTO must ensure the integration of reliability practices within an interconnection and market interface practices among regions.

Appendix B. NERC Transmission Planning Reliability Standards[82]

TPL-001-0.1 System Performance Under Normal (No Contingency) Conditions (Category A)

System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

TPL-001-1 System Performance Under Normal Conditions

System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

TPL-001-2 Transmission System Planning Performance Requirements

Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

TPL-002-0b System Performance Following Loss of a Single Bulk Electric System Element (Category B)

System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

TPL-002-1b System Performance Following Loss of a Single BES Element

System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

TPL-003-0a System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)

System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

TPL-003-1a System Performance Following Loss of Two or More BES Elements System simulations and associated assessments are needed periodically to ensure that reliable

[82] Source: www.nerc.com

systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

TPL-004-0 System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

TPL-004-1 System Performance Following Extreme BES Events

System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

TPL-005-0 Regional and Interregional Self-Assessment Reliability Reports

To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.

TPL-006-0 Data From the Regional Reliability Organization Needed to Assess Reliability

To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.

TPL-006-0.1 Data From the Regional Reliability Organization Needed to Assess Reliability

To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.

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