FINAL REPORT

# Western Planning Regions and Transmission Planning Coordination

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*Heidi Pacini, Kiran Kumaraswamy, Ken Collison*

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# Executive Summary

Transmission planning in the Western Interconnection (WI) has evolved to include a hierarchy of local, regional, and interconnection-wide coordinated planning efforts. Federal Energy Regulatory Commission (FERC) Order 890 issued in 2007 formalized the WI's regional and interconnection-wide planning efforts, establishing the four western Planning Regions currently in existence today as the forums for coordinated regional transmission planning and the Western Electricity Coordinating Council (WECC) as the facilitator of interconnection-wide planning coordination.

In 2011, FERC issued Order 1000, which expanded the obligations of public utility Transmission Providers to participate in a robust, open and transparent regional planning and interregional coordination process that identifies more efficient or cost-effective regional/interregional transmission and non-transmission solutions and provides a mechanism for regional/interregional cost allocation. Transmission Providers in the WI already participating in Order 890-compliant regional planning processes facilitated by the western Planning Regions opted to continue using these forums to comply with Order 1000. The extent to which each western Planning Region revised its existing regional transmission planning process to comply with the requirements set forth by Order 1000 varied, but each Region initiated a comprehensive stakeholder-driven process to make the necessary adjustments to its planning process.

On March 25, 2015 the Northern Tier Transmission Group (NTTG) became the second Region in the WI to achieve full compliance with the regional planning requirements of Order 1000. The California Independent System Operator (CAISO) was the first Region in any interconnection to achieve this distinction.

Today, even though regional compliance filings for the public utility Transmission Providers of ColumbiaGrid and WestConnect are still pending, all four western Planning Regions are currently in the process of conducting regional transmission planning under Order 1000. For WestConnect, 2015 will be a year of firsts as it performs its first region-wide reliability assessment and prepares a production cost model dataset to perform economic/congestion studies. At the other end of the spectrum, CAISO's 2015-2016 transmission planning process will look largely unchanged from its pre-Order 1000 planning efforts.

This difference among the Regions is not isolated. The regional transmission planning processes of the four western Planning Regions differ in everything from the duration of the planning cycle to the scope of the technical studies used to identify reliability, economic, and public policy-driven transmission needs. The Regions are confronting these differences as they navigate the new waters of interregional coordination. Coordination among the four Regions is not new, but no formal, documented process for coordinating planning activities across regions has ever been defined. This will change as the Planning Regions establish interregional coordination procedures to achieve the west-wide implementation of interregional Order 1000 by October 1, 2015.

Important topics to be addressed in the development of the interregional coordination procedures will include ways in which the consistency of planning data and assumptions across the Regions can be improved and maintained. Direct requests for input and data at established points during the regional planning processes, if accompanied by commitments to provide that input, could improve the consistency of planning data utilized within the regional processes. A centralized, continuously updated repository of planning data could maintain the consistency of this data by enabling access to a common set of current assumptions for any variety of transmission planning activities, including the joint evaluation by the Regions of interregional transmission projects as well as for interconnection-wide studies.

Up to this point, many interregional coordination efforts have been facilitated at the WECC level as part of the planning activities of the Planning Coordination Committee (PCC) and Transmission Expansion Planning Policy Committee (TEPPC). The value of the PCC and TEPPC activities, and in particular their efforts to assimilate and make available interconnection-wide power flow and production cost model data, has been endorsed by the Regions and their members and stakeholders. However, the independent timelines of the various planning activities necessitates the need for ad hoc updating of the WECC planning data, which has contributed in the past to inconsistencies between planning efforts. Now, the interregional coordination efforts have put renewed focus on the scope and timing of coordinated planning activities conducted in the regional, interregional, and interconnection-wide planning forums to ensure that the planning activities serve to satisfy the transmission planning obligations of each organization, and are efficient and non-duplicative. Over the coming months, WECC and the western Planning Regions will address the topic of regional/interconnection-wide planning coordination as the regions establish their interregional coordination process and WECC assesses the scope, structure, and roles of its committees and looks to focus its efforts on addressing the top reliability challenges facing the WI.

The hierarchy of local, regional, and interconnection-wide coordinated planning efforts collectively ensures the continued reliable and efficient operation of the bulk electric system. Efficient and effective coordination of these efforts is key to ensuring transmission planning efforts are meaningful and non-duplicative. At the same time, stakeholders play a key role in ensuring transmission planning efforts are transparent and produce a robust portfolio of transmission expansions that have a high likelihood of being needed and well-utilized under the most likely, but uncertain energy futures. All four western Planning Regions and WECC provide for the input and participation of a broad range of stakeholders in the transmission planning process. The extent to which this opportunity is exercised, however, varies across the interconnection. For example, while the WestConnect regional planning process allows for voting membership of state agencies and key interest groups on the Planning Management Committee, no entities have yet elected to participate as members in the process. At the other end of the spectrum is the CAISO transmission planning process, in which state agencies work together with the CAISO to identify scenarios and ensure a broad range of policy considerations are incorporated in the technical studies. The result of this coordination and collaboration is a robust and comprehensive transmission planning process, which is the goal of each local, regional, and interconnection-wide planning effort.

It is clearly a dynamic time with regard to planning coordination in the Western Interconnection. This report is intended to provide an overview of the state of the WI as it relates to regional transmission planning and coordinated planning efforts. This report is written primarily for those who are unfamiliar with the four western Planning Regions subsumed under the WI and other coordinated transmission planning efforts in the WI, and how these efforts are collectively being coordinated to perform interregional transmission planning as well as to provide an interconnection-wide perspective on future transmission needs of the western power system. Because interregional and Region-WECC coordination efforts are currently a topic under significant discussion and development, this report also serves to provide a brief description of regional transmission planning efforts in the Eastern Interconnection. The information presented is intended to describe both the technical approach to regional transmission planning outside the west, as well as the approach to coordinating transmission planning efforts across regions and at an interconnection-wide level.

A summary of the information compiled in this report with regard to the western Planning Regions and Eastern Interconnection examples of regional transmission planning efforts is presented in Table 1 and illustrates the broad spectrum of coordinated regional transmission planning processes, all of which share a common goal of ensuring the continued reliable and efficient operation of the bulk electric system.

**Table 1: Regional Transmission Planning Overview**

| | Western Interconnection | | | | Eastern Interconnection | |
|---|---|---|---|---|---|---|
| | **CAISO** | **NTTG** | **ColumbiaGrid** | **WestConnect** | **SPP** | **MISO** |
| ***Region Overview*** | | | | | | |
| **No. of Planning Parties** | 16 | 6 | 11 | 13 | 16 Transmission Owner members | 50 Transmission Owner members |
| **States Spanned** | CA | CA, ID, MT, OR, WA, WY, UT | WA, OR, ID, MT | AZ, CA, CO, MT, NM, NV, TX, UT, WY | 8 states | 15 states |
| **Approximate Peak Demand, 2014 (GW)** | 47 GW (coincident) | 22 GW (estimated coincident) | 22 GW (estimated coincident) | 56 GW (2012 non-coincident) | 49 GW (coincident) | 96 GW (coincident) |
| **Customers Served** | 30 Million | 4 Million | 3 Million | 10 Million | 15 Million | 42 Million |
| **Miles of High Voltage Transmission** | 26,000 | 29,000 | 22,000 | 40,000 | 49,000 | 50,000 |
| ***Order 1000 Compliance Status*** | | | | | | |
| **Regional** | Fully compliant | Fully compliant | Awaiting FERC Order, tariff changes effective 1/1/15 | Awaiting FERC Order, tariff changes effective 1/1/15 | Awaiting FERC Order, tariff changes effective 3/30/14 | Awaiting FERC Order, tariff changes effective 6/1/2013 |
| **Interregional** | Awaiting FERC Order, tariff changes effective 10/1/15 | Awaiting FERC Order, tariff changes effective 10/1/15 | Awaiting FERC Order, tariff changes effective 1/1/15 | Awaiting FERC Order, tariff changes effective 10/1/15 | Awaiting FERC Order, tariff changes effective 3/30/14 for SPP-MISO, 1/1/15 for SPP-SERTP | Awaiting FERC Order, tariff changes effective 3/30/14 for SPP-MISO, 1/1/15 for MISO-SERTP, 1/1/2014 MISO-PJM |
| ***Regional Planning Process*** | | | | | | |
| **Planning Cycle** | Annual | Biennial | Biennial, Annual study program | Biennial | Triennial, Annual near-term studies | Annual |
| **Governance and Direction of Planning Activities** | Board of Directors | Steering Committee | Board of Directors | Planning Management Committee | Board of Directors | Board of Directors, System Planning Committee |
| **Method for Participation by States** | Stakeholder, CPUC/CAISO MOU | Committee Membership | Stakeholder, Study Team Participant | PMC Member | Stakeholder, Regional State Committee | Stakeholder, Organization of MISO States |
| **Primary Modeling Tools** | GE-PSLF (reliability) GridView (economic) | PowerWorld (reliability) GridView (economic) | PowerWorld, GE-PSLF (reliability) GridView (economic) | PowerWorld (reliability) GridView (economic) | PTI PSS/E (reliability) PROMOD (economic) | PTI PSS/E (reliability) PROMOD (economic) EGEAS (generation expansion) |

| | Western Interconnection | | | | Eastern Interconnection | |
|---|---|---|---|---|---|---|
| | **CAISO** | **NTTG** | **ColumbiaGrid** | **WestConnect** | **SPP** | **MISO** |
| **Types of Planning Studies Performed (not exhaustive for RTOs)** | • 5-year, 10-year<br>• Multiple system conditions<br>• Reliability & Economic are separate, coordinated<br>• Generator Interconnection<br>• Local Capacity Requirements | • 10-year<br>• Five stressed hours<br>• Reliability & Economic via round-trip approach | • 1, 5, 10-year<br>• Multiple system conditions<br>• Reliability & Economic separate<br>• Variable Transfer Limits | • 10-year<br>• Single system condition in 2015<br>• Reliability & Economic separate | • 5, 10, 20-year<br>• Multiple system conditions<br>• Reliability & Economic are coordinated<br>• Generator Interconnection | • 2, 5, 10, 15-year<br>• Multiple system conditions<br>• Reliability & Economic are separate, coordinated<br>• Generator Interconnection<br>• Resource Adequacy |
| **Primary Sources of Modeling Assumptions** | • Unified planning assumptions<br>• CPUC/CEC<br>• WECC-PCC Base Cases<br>• TEPPC 10-year Production Cost dataset | • Data submittals<br>• WECC-PCC Base Cases<br>• TEPPC 10-year Production Cost dataset | • Member data<br>• WECC-PCC Base Cases<br>• TEPPC 2010 Production Cost dataset | • Member data<br>• WECC-PCC Base Cases<br>• TEPPC 10-year Production Cost dataset | • Members<br>• Neighboring Regions<br>• NERC MMWG Base Cases<br>• Vendor production cost dataset | • Members<br>• Neighboring Regions<br>• NERC MMWG Base Cases<br>• Vendor production cost dataset |
| **Use of Scenarios or Sensitivities** | • Alternative RPS resources portfolios for policy-driven needs<br>• Sensitivities for cost/benefit evaluations<br>• Special studies | • Public policy considerations<br>• Informs the regional plan, not used to identify projects<br>• Sensitivities for cost/benefit evaluations | • Reliability sensitivities<br>• Economic analysis<br>• Sensitivities for cost/benefit evaluations | • Scenario request window<br>• Unknown how they will be applied to the process<br>• Sensitivities will be for cost/benefit evaluations | • Transmission needs under alternative futures (10, 20-year)<br>• Informs consolidated portfolio of projects | • Robustness testing<br>• “No regrets” projects (MVP portfolio) |
| **Competitive Solicitation Process?** | Yes | No | No | No | Yes | Yes |
| **Key Drivers for New Transmission** | Reliability, Public Policy, Economic | Reliability | Reliability | Unknown, new process | Reliability, Public Policy, Economic | Reliability, Public Policy, Economic |

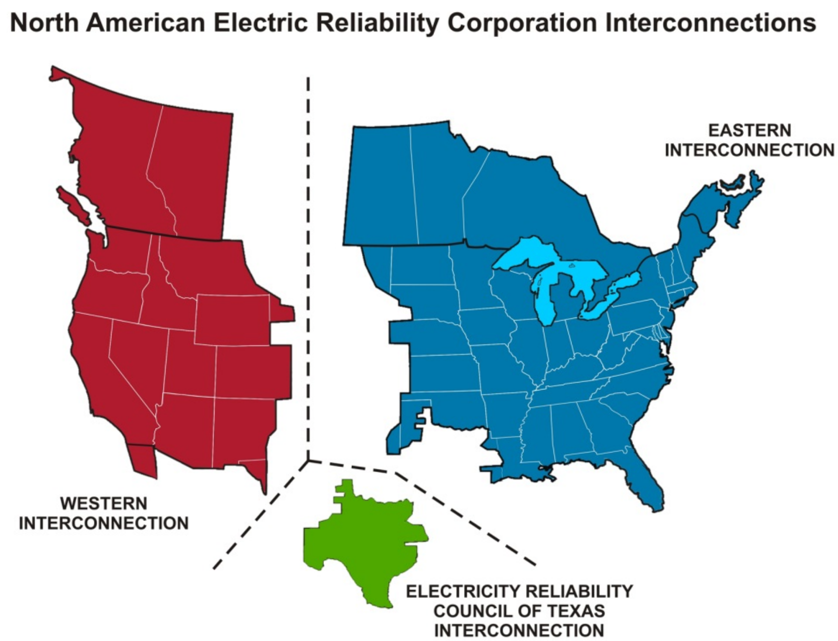
| | Western Interconnection | | | | Eastern Interconnection | |
|---|---|---|---|---|---|---|
| | **CAISO** | **NTTG** | **ColumbiaGrid** | **WestConnect** | **SPP** | **MISO** |
| ***Current Planning Cycle*** | | | | | | |
| **Planning Cycle** | 2015-2016 | 2014-2015 | 2015 | 2015 (abbreviated one-year cycle) | 2016-cycle ITP studies delayed | MTEP15 |
| **Planning Horizon** | 2017, 2020, 2025 | 2024 | 2016/17, 2020/21, 2025/26 | 2024 | NA | Through 2024 |
| **Current Study Plan** | Link | Link | Link | Link | NA | NA |
| **Most Recent Regional Plan** | Link | Link | Link | Link | 2015 ITP 10<br>2015 ITPNT<br>2015 STEP | MTEP14<br>MTEP14 Book 1 |

# Introduction: Transmission Planning History and Evolution

Transmission planning is an ongoing, iterative process that involves the analysis of forecasted system conditions to determine the need for expansion to cost-effectively maintain reliability, serve growing loads, and accommodate the interconnection of new generating resources. The interconnected nature of the transmission system and the laws of physics complicate the planning process in that electricity does not take the most direct route from one point to another, but rather flows instantaneously over all available pathways, thereby creating the potential for both normal activity and emergency events to impact more than just the local system.

As illustrated in Figure 1, the Western Interconnection (WI) is one of three interconnected transmission systems that serve the electricity demands of the U.S. It spans over 1.8 million square miles from the Canadian provinces of Alberta and British Columbia to the northern portion of Baja California, Mexico and all or portions of 14 Western States in between.[1] The WI comprises 27 percent of the high voltage transmission circuit miles in North America.

**Figure 1: North American Transmission Interconnections**




***Source:*** *U.S. Department of Energy*

The regulation and oversight of transmission planning both in North America generally and specifically in the WI has evolved substantially. Early North American transmission planning efforts were conducted by local utilities in isolation from one another, under the presumption that neighboring systems would be available to provide assistance under emergency conditions but that the local system would be

[1] WECC, "2013 State of the Interconnection Report," https://www.wecc.biz/Reliability/2013_WECC_SOTI_Report.pdf.

robust enough to provide reliable service under normal, day-to-day operations. Over time, utilities recognized not only that efficiencies could be gained by pooling resources over larger footprints, but also that system disturbances could have far-reaching and catastrophic impacts that could be mitigated through better coordination. The Northeast Blackout of 1965 was one such catastrophic event, and it led to the creation of the North American Electric Reliability Council (NERC) and smaller supporting regional entities.[2] NERC's role was to establish uniform reliability criteria for the planning and operation of the electric power system, in order to reduce the likelihood of further widespread disruptions.

Compliance with the original NERC standards was voluntary until 2003, when another blackout in the Northeast affected more than 50 million people. This event led to a provision in the Energy Policy Act of 2005 making compliance with NERC reliability standards mandatory. Under the new law, the Federal Energy Regulatory Commission (FERC) was charged with ultimate oversight of bulk electric system reliability and finalizing rules for the certification of an electric reliability organization (ERO) to develop, approve, and enforce mandatory electric reliability standards. FERC certified NERC as the ERO in 2006, and NERC in turn has delegated its authority to smaller, regional entities including the Western Electricity Coordinating Council (WECC) in the Western Interconnection.

In addition to the emergence of reliability standards, the planning and operation of the electric system also changed substantially after the Energy Policy Act of 1992, as FERC mandated open access to the transmission system. FERC's Order No. 888 and 889 required transmission owners to provide transmission service to other suppliers of electricity on the same terms and conditions as they provide it to themselves, and to maintain timely and accurate day-to-day information about the availability of the transmission system.[3] This open access to the transmission system paved the way for the emergence of competitive generation markets and the formation of Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) to administer the transmission grid on a regional basis. In addition to operating the transmission system in accordance with NERC reliability criteria, ISO/RTOs ensure nondiscriminatory access to the transmission system, and manage and plan for its reliability. Voluntary RTOs and ISOs have formed in many regions of the U.S. The California Independent System Operator (CAISO) and Alberta Electric System Operator (AESO) are the only ISO/RTO organizations in the Western Interconnection.

## Transmission Planning in the Western Interconnection

Even in the absence of additional ISO/RTOs in the WI, transmission planning in the West has evolved to include a hierarchy of local, regional, and interconnection-wide coordinated planning efforts with the common goal of ensuring the continued reliable and efficient operation of the bulk electric system. With FERC's issuance of Order 890 in 2007, all public utility transmission providers were required to participate in sub-regional and regional transmission planning processes to be described in attachments

[2] EISPC and NARUC, "Transmission Planning White Paper", January 2014.

[3] The terms and conditions of transmission services offered by transmission providers are maintained within their posted Open Access Transmission Tariffs (OATTs).

to their Open Access Transmission Tariffs (OATTs).[4] These processes were required to involve both reliability and economic considerations, and to be conducted in a coordinated, open, and transparent manner. The four western Planning Regions (Regions) currently in existing today – CAISO, Northern Tier Transmission Group, ColumbiaGrid, and WestConnect – were forums for collaboration and coordination before Order 890, but Order 890 served to formalize and memorialize regional planning efforts in the WI, and further established WECC as the facilitator of interconnection-wide planning coordination.

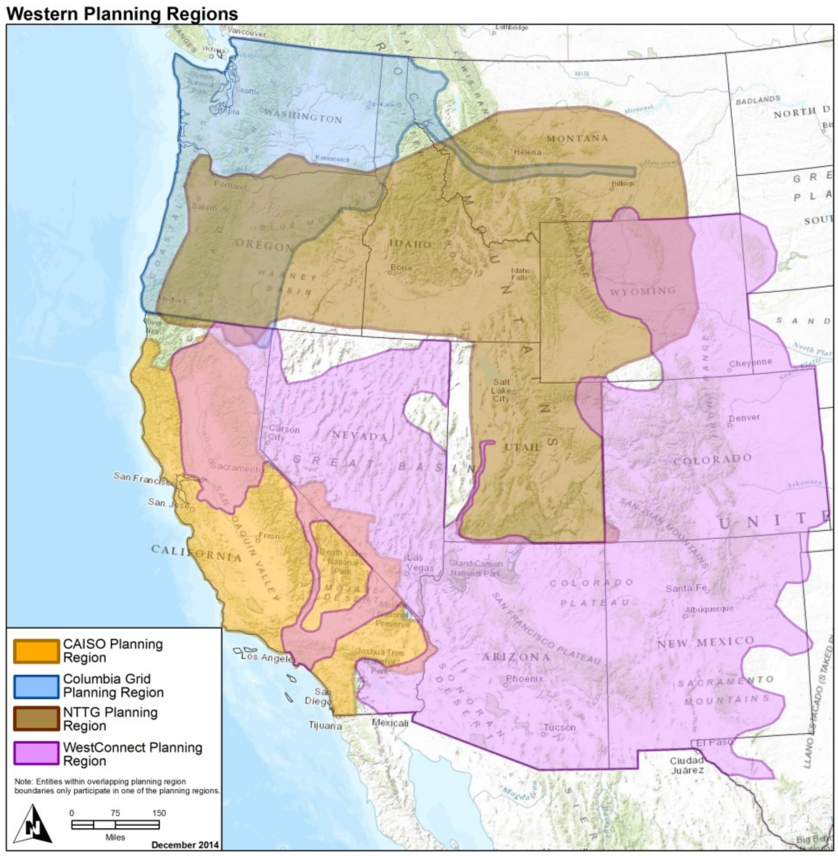
WECC's interconnection-wide transmission expansion planning efforts greatly expanded in 2010 when it received a grant from the U.S. Department of Energy under the American Recovery and Reinvestment Act to expand the breadth and depth of stakeholder involvement in interconnection-wide transmission planning activities, add new tools for transmission planning, and create interconnection-wide transmission plans.

Most recently, in 2011, FERC issued Order 1000[5] to further reform electric transmission planning and cost allocation requirements for public utility transmission providers. Order 1000 did not replace Order 890, but rather was designed to "correct remaining deficiencies with respect to transmission planning processes and cost allocation methods" first established by Order 890. Transmission providers in the WI already participating in Order 890-compliant regional planning processes facilitated by the western Planning Regions opted to continue using these forums to comply with Order 1000. The extent to which each Region had to revise its existing regional transmission planning process to address the requirement set forth by Order 1000 varied, but each Region initiated a comprehensive stakeholder-driven process to make the necessary adjustments to its planning processes. The four western Planning Regions conducting regional transmission planning in compliance with Order 1000 are illustrated in Figure 2.

[4] In the context of Order 890, sub-regional transmission planning groups were groups understood today to be regional planning organizations such as CAISO, Northern Tier Transmission Group, ColumbiaGrid, and WestConnect. Regional planning referred to coordinated planning efforts at the interconnection-wide level in the WI by WECC.

[5] http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

**Figure 2: Western Planning Regions**




***Source**: WestConnect*

## Report Outline

This purpose of this report is to provide an overview of the state of the WI as it relates to the coordination of regional transmission planning. This report is written primarily for those who are unfamiliar with the four western Planning Regions subsumed under the WI and other coordinated transmission planning efforts in the WI, and how these efforts are collectively being coordinated to perform interregional transmission planning as well as to provide an interconnection-wide perspective on future transmission needs of the western power system.

Chapters 1-4 of this report provide individual summaries of the four western Planning Regions. They contain information regarding the Regions' organizational structures, sources of funding, history of regional transmission planning efforts, status of compliance with FERC Order 1000, and a summary of their current regional transmission planning process including their approach to building planning models and the scope of the technical studies they have performed. It is worth noting that while requirements for regional cost allocation are a significant component of the regional transmission planning process, the Planning Region summaries in this report focus on the modeling and technical study aspects of the regional planning processes. The summary sections also include a comparison of each Region's study plan for their active planning cycle, as well as a high-level comparison of some of the major aspects of the regional planning processes.

Following the Region summaries, Chapter 5 contains a description of the interregional coordination efforts of the western Planning Regions, specifically as it relates to the requirements for interregional planning coordination set forth in FERC Order 1000. On December 18, 2014 FERC conditionally accepted the interregional compliance filings submitted by the western Planning Regions, subject to an additional compliance filing to be made by each Region. Each Region has addressed these directives in a subsequent filing to FERC, and while the Regions wait for another compliance order, the effective date for the interconnection-wide implementation of Order 1000 on interregional planning coordination has been set for October 1, 2015.

Chapter 6 provides an overview of the interconnection-wide coordinated planning efforts of the Western Electricity Coordinating Council (WECC). At the interconnection-wide level, WECC provides a forum for the coordination of local, regional, and interconnection-wide issues. WECC conducts coordinated transmission planning through its Planning Coordination Committee and TEPPC activities. There are ongoing discussions regarding the approach to WECC's coordinated transmission planning efforts with the western Planning Regions.

Finally, as interregional and Region-WECC coordination efforts are currently a topic under significant discussion and development, Chapter 7 serves to provide a brief description of regional transmission planning efforts in the Eastern Interconnection. The information presented is intended to describe both the technical approach to regional transmission planning outside the west, as well as the approach to coordinating transmission planning efforts across regions and at an interconnection-wide level.

All of the information contained within this report was compiled using publicly available information regarding the regional, interregional, and interconnection-wide transmission planning efforts described. Key sources of information accessed for this report include business practice manuals or similar, current and past study plans, recent transmission plans, and OATTs filed for compliance with Order 1000. Links to websites and documents with additional information regarding the processes and efforts described are provided to enable the reader to find additional explanation and detail where desired. It is important to note that because the regional planning processes for some of the western Planning Regions are still under consideration by FERC, some aspects of the planning processes described within this report may be subject to change.

# Chapter 1: WestConnect

WestConnect was established as an organization of electric utility companies working collaboratively to address common issues in the western wholesale electricity market. It was formed through a Memorandum of Understanding (MOU) on December 6, 2004, later updated as an Amended and Restated MOU on February 14, 2007 which remains in effect today. In addition to working together under the WestConnect Steering Committee (SC) to identify, develop, and implement cost-effective wholesale market enhancements, WestConnect members have collaborated formally with regard to regional transmission planning efforts under the Planning Management Committee (PMC) since 2007 in response to FERC Order 890. WestConnect's regional transmission planning activities are set to expand significantly beginning in 2015 under FERC Order 1000.

### *WestConnect Highlights*

- WestConnect's public utility Transmission Providers are awaiting an Order from FERC on their third round of compliance filings addressing the regional planning requirements of Order 1000.
- FERC has accepted an effective date of January 1, 2015 for their revised OATT attachments.
- WestConnect is in the process of executing an abbreviated Order 1000 planning cycle in 2015. The first full biennial planning cycle will commence in 2016.
- Under its Order 1000 regional planning process, WestConnect will, for the first time, conduct a reliability assessment of the entire WestConnect planning footprint, in addition to performing an assessment of the economic and public policy-driven needs of the region.

## 1.1 Regional Transmission Planning

Public utility transmission owners (TOs) in the western and southwestern portions of the Western Interconnection achieved compliance with the transmission planning requirements of Order 890 by entering into the WestConnect Project Agreement for Subregional Transmission Planning (STP Agreement) on May 23, 2007 (later amended on January 14, 2009). The WestConnect STP Agreement, signed by the eighteen entities listed in Table 2, established a formal commitment of the signatory parties to fund and oversee the WestConnect regional planning process. The WestConnect STP Agreement also established the PMC, made up of one representative from each of the signatory parties. The PMC was tasked with implementing a regional planning process that would promote open and transparent transmission planning, incorporate the involvement of stakeholders, and culminate in the development of a ten-year integrated regional transmission plan for the WestConnect footprint on an annual basis using input from the study efforts of the WestConnect Subregional Planning Groups (SPGs).

### 1.1.1 Planning Footprint

The WestConnect regional planning footprint under Order 890, as illustrated in Figure 1, encompasses the transmission systems of eighteen Western transmission service providers and spans all or portions of eleven Western States including: Arizona, California, Colorado, Montana, Nebraska, New Mexico, Nevada, South Dakota, Texas, Utah, and Wyoming. The systems of these transmission providers collectively span approximately 40,000 line miles, and serve nearly 10 million retail customers, with a non-coincident peak load of 56,000 MW.[6]

**Figure 3: WestConnect Order 890 Regional Planning Footprint**


***Source**: WestConnect*

**Table 2: WestConnect Order 890 PMC Members**

| WestConnect Order 890 PMC Members | |
|---|---|
| Arizona Public Service | Southwest Transmission Cooperative |
| Basin Electric Power Coop | Transmission Agency of Northern California |
| Black Hills Corporation | Tri-State G & T Association |
| El Paso Electric | Tucson Electric Power |
| Imperial Irrigation District | Western Area Power Administration |
| NV Energy | Los Angeles Department of Water and Power |
| Xcel Energy | Platte River Power Authority |
| Public Service New Mexico | Colorado Springs Utility |
| Sacramento Municipal Utility District | |
| Salt River Project | |

Three SPGs also function within the WestConnect planning footprint: the Southwest Area Transmission Planning Group (SWAT), the Sierra Subregional Planning Group (SIERRA), and the Colorado Coordinated

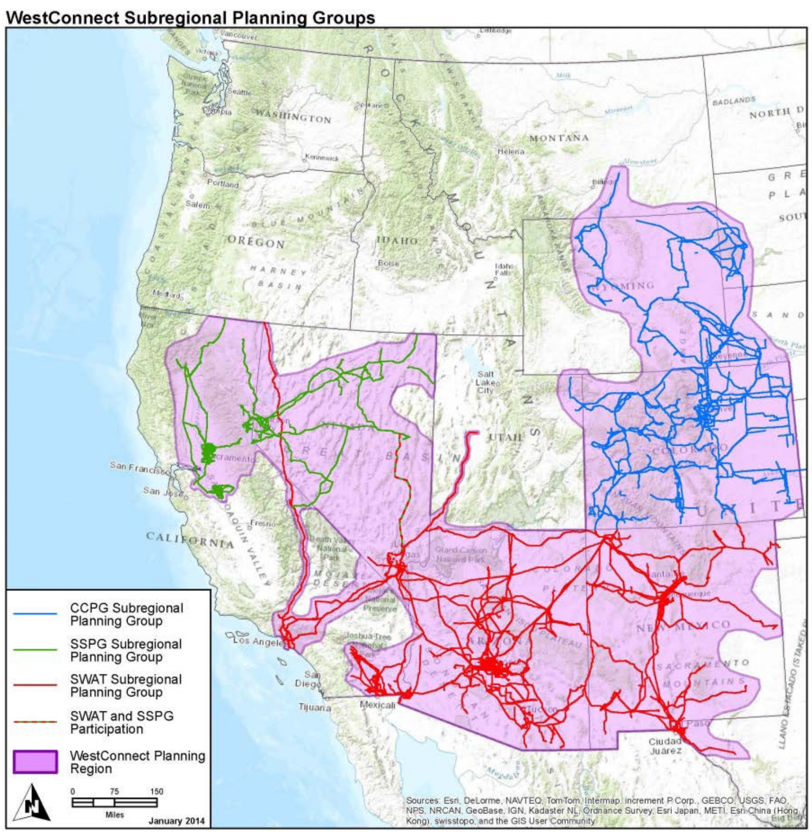
[6] WestConnect Order 890 PMC Member statistics for 2012

Planning Group (CCPG). Each of these SPGs operates under an independent charter that defines their roles and responsibilities as an SPG. These roles and responsibilities include:

- Coordinating power flow base cases for use by SPG study participants,
- Defining subregional study plans, providing study resources, and performing technical studies as identified in the study plans, and
- Providing a forum for the coordination and peer review of member planning studies and 10-year transmission plans.

The WestConnect regional planning process was in turn designed to coordinate, rather than duplicate, the subregional planning efforts.

**Figure 4: WestConnect Subregional Planning Group Footprints**




***Source**: WestConnect*

### 1.1.2 Order 890 Annual Ten-Year Transmission Plan

WestConnect began producing its Annual Ten-Year Transmission Plan in 2007 on behalf of its subregional planning participants and stakeholders. This transmission plan incorporated the results of the annual SPG transmission planning processes, provided a summary of the WestConnect and SPG stakeholder activities, and documented ten-year transmission projects of the PMC members as well as other entities who submitted qualified projects into the WestConnect Transmission Planning Project List (TPPL). However, no region-wide technical studies were performed by WestConnect as part of its Order 890 regional planning efforts.

On February 19, 2015 the WestConnect PMC approved the final WestConnect Annual Ten-Year Transmission Plan under Order 890. All regional planning conducted by WestConnect starting January 1, 2015 will be subject to the requirements set forth by FERC Order 1000.

## 1.2 WestConnect Order 1000 Regional Planning

Seven of the eighteen WestConnect Order 890 PMC members are FERC-jurisdictional public utilities including: Arizona Public Service, El Paso Electric, NV Energy, Xcel Energy, Public Service New Mexico, Tucson Electric Power, and Black Hills Corporation. They are therefore subject to compliance with the regional planning requirements set forth by Order 1000. From 2011 through 2014, these utilities and WestConnect's other PMC members initiated a stakeholder process to help guide the development of an expanded WestConnect Regional Transmission Planning Process and the associated compliance filings to be submitted to FERC that would satisfy the requirements of Order 1000.

WestConnect's jurisdictional TOs have filed three rounds of regional compliance filings with FERC. The most significant issues addressed in FERC's orders on the regional compliance filings have been with regard to the method for participation of non-public utility transmission providers, and WestConnect's obligation to identify more efficient or cost effective regional solutions to identified transmission needs in the absence of stakeholder submitted alternatives. The most recent regional filings were made on November 17, 2014,[7] in response to FERC's second regional order issued on September 18, 2014. In this second regional order, FERC required the WestConnect public utility TOs to address, among other compliance directives, a process for non-public utility TO members to elect to accept or not the cost allocations assigned to it by WestConnect for individual projects, file the agreement that must be signed in order to become a member of the planning process, and submit a process whereby WestConnect will select a single project developer eligible to utilize the cost allocation for projects selected in the regional transmission plan. In the same order, FERC accepted an effective date of the tariff revisions describing the regional planning process of January 1, 2015, essentially requiring the TOs to initiate their first Order 1000 planning cycle on January 1, 2015.

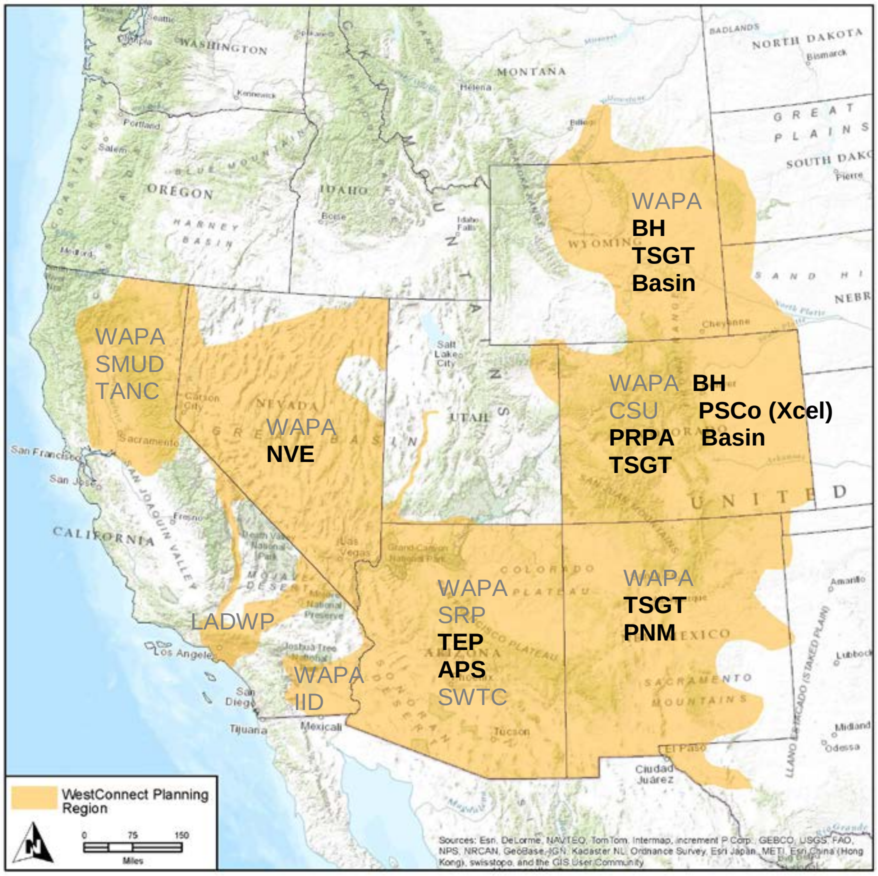
To prepare for the commencement of the first Order 1000 planning cycle, the WestConnect Planning Participation Agreement (PPA) was put into effect on December 16, 2014. The PPA was drafted to establish the rights and obligations of parties to the agreement to carry out the WestConnect Regional Transmission Planning Process developed for compliance with Order 1000. The PPA effectively suspended the previous STP Agreement and the Planning Management Committee that the STP Agreement had established. The PPA, in turn, has established a new Planning Management Committee, which is responsible for administering the new Order 1000-compliant WestConnect Regional Transmission Planning Process.

As of March 1, 2015, ten TOs have signed the WestConnect PPA to become members of the new Order 1000 PMC. Three of these TOs are not subject to FERC jurisdiction (Tri-State G & T Association, Basin Electric Power Coop, and Platte River Power Authority). It is anticipated that more non-public utility TOs will sign the PPA and join the WestConnect PMC such that the WestConnect planning footprint for Order 1000 regional planning will continue to match the footprint shown in Figure 1. Until that time, however, WestConnect will perform regional planning for only those TOs who have signed the PPA to become

[7] Regional Compliance Filings filed by the WestConnect public utility TOs in response to FERC Order 1000 can be accessed here: http://www.westconnect.com/planning_order_1000_rc_filing.php.

Enrolled TOs.[8] The extent to which the transmission planning data and assumptions of TOs previously participating in the WestConnect regional (Order 890) planning process but which have not yet signed the PPA will be incorporated into the Order 1000 planning activities is uncertain. To-date, however, the power flow models needed for the Order 1000 reliability analysis were developed by the WestConnect SPGs and included updates provided to them by all of the previous eighteen WestConnect Order 890 PMC members.

**Figure 5: Anticipated WestConnect Order 1000 Planning Footprint**




***Source**: WestConnect*

*Note: Entities in **grey** text in Figure 3 are TOs that participated in the WestConnect Order 890 planning process but have not yet signed the WestConnect PPA.*

### 1.2.1 Planning Management Committee Structure

WestConnect's new regional planning process is managed by the Order 1000 regional transmission Planning Management Committee (PMC). Three subcommittees operate under the PMC as illustrated in Figure 4. To-date, two working groups have also been established by the PMC to operate under the Planning Subcommittee: the Power Flow Work Group, and the Expansion Planning Work Group.

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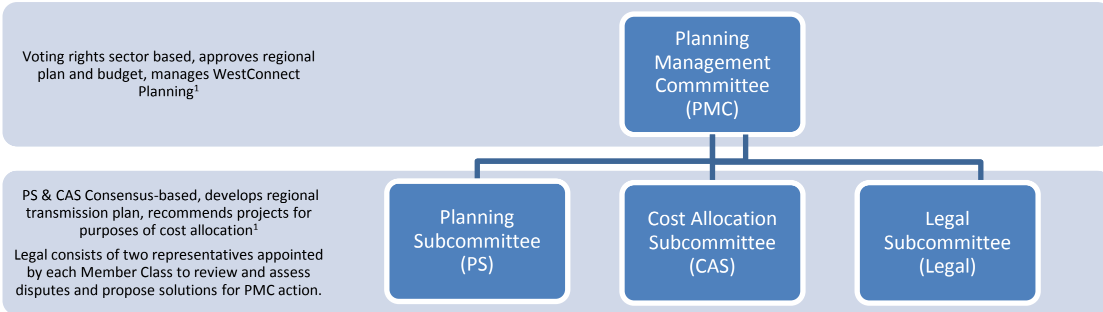
[8] WestConnect's membership sectors for the Order No. 1000 PMC are described in more detail in the subsequent section.

**Figure 6: Planning Management Committee Structure**




***Source**: WestConnect Regional Planning Process Business Practice Manual*

The responsibilities of the three PMC subcommittees are summarized below.

**PS Responsibilities**: Reviewing and making recommendations to the PMC for the development of study plans, establishing base cases, evaluating potential solutions to regional transmission needs, producing and recommending the Regional Transmission Plan for PMC approval, and coordinating with the CAS.

**CAS Responsibilities**: Performing and/or overseeing the performance of the cost allocation methodology. The CAS is also tasked with reviewing and making recommendations to the PMC for modifying definitions of benefits and cost allocation methodology as necessary to meet WestConnect planning principles, and recommending projects to the PMC for purposes of cost allocation identified in the Regional Planning Process.

**Legal Subcommittee Responsibilities**: Reviewing, assembling, and proposing solutions to the PMC for formal or informal disputes arising under the PPA.

WestConnect does not maintain its own dedicated staff for performing planning-related work. Rather, the PMC has hired an independent planning consultant to support the planning committee structure and to perform the majority of the technical analysis associated with the regional planning process. Support for the regional planning activities is also provided by the PMC members and the WestConnect SPGs.

### 1.2.2 PMC Membership Sectors

Membership on the PMC is classified into five membership sectors including:

1. Transmission Owners with Load Serving Obligations (TOLSO):
    a. Enrolled Transmission Owner (ETO): A TO Member that enrolls in the TO Member Sector for purposes of Cost Allocation pursuant to FERC Order 1000, and
    b. Coordinating Transmission Owner (CTO): A TO Member that joins the TO Member Sector without enrolling for FERC Order 1000 cost allocation purposes
2. Transmission Customers (TC)
3. Independent Transmission Developers and Owners (ITDO)
4. State Regulatory Commission (SRC)

5. Key Interest Groups (KIG)

In order to join WestConnect as a TOLSO member, the entity must provide transmission service and own a minimum of one hundred circuit miles or $100 million of original installed cost of transmission infrastructure rated at 115 kV or higher within the Western Interconnection, and serve a minimum of 150 MW of retail and/or wholesale network load within the Western Interconnection.

Within the TOLSO member sector are two sub-sectors: members that can enroll in the TOLSO member sector for purposes of cost allocation pursuant to Order 1000 (i.e. as an ETO), and those that can join to participate in the WestConnect Regional Transmission Planning Process without enrolling for Order 1000 cost allocation purposes (i.e. as a CTO). FERC-jurisdictional TOs that meet the criteria for membership in the TOLSO member sector may only join the PMC as an ETO, whereas a non-public utility that meets the criteria for membership in the TOLSO member sector may elect to join either as an ETO or CTO, or they may join any other member sector for which they qualify. If a non-public utility joins a member sector other than the TOLSO sector, the PMC will not perform the function of regional transmission planning for that entity.[9]

The ETO and CTO member sub-sectors were created in order to provide for the participation of non-public utility TOs in the WestConnect regional planning process. Cost allocation results produced from the WestConnect regional planning process are binding on identified project beneficiaries, with the following exceptions provided for non-public utilities and CTOs:

- Non-public utilities participating in the WestConnect regional planning process as an ETO may unenroll with respect to a planning cycle in accordance with the provisions set forth in the regional tariffs and Section 5.4 of the PPA.[10]
- By unenrolling (and thereby becoming a CTO member of the TOLSO sector), the non-public utility member of the TOLSO sector will not be subject to cost allocation for any projects for which it received a cost allocation for the first time in the Regional Transmission Plan.
- At the same time, a CTO member has the right to decide whether or not it will accept a regional cost allocation for each separate transmission facility proposed for selection in the Regional Transmission Plan for which it is identified as a beneficiary in accordance with the provisions set forth in the regional tariffs and Section 7.6 of the PPA.

The processes for unenrolling and for accepting a regional cost allocation are currently under review by FERC.

### 1.2.3 Funding for Regional Planning Activities

The various PMC membership sectors have different funding obligations. SRC PMC Members and KIG PMC Members that are state energy offices or state consumer representatives have no obligation to fund activities of the PMC in support of the WestConnect Regional Planning Process. KIG Members that are NGOs are subject to a tiered dues structure based on the organization's annual operating budget as set forth in the PPA. KIG PMC Members, except those described above, and TC and ITDO PMC Members are required to pay dues of $5000/year. TOLSO PMC Members fund the remainder of expenses to carry out the activities and functions of the WestConnect Regional Planning Process that are in excess of funds

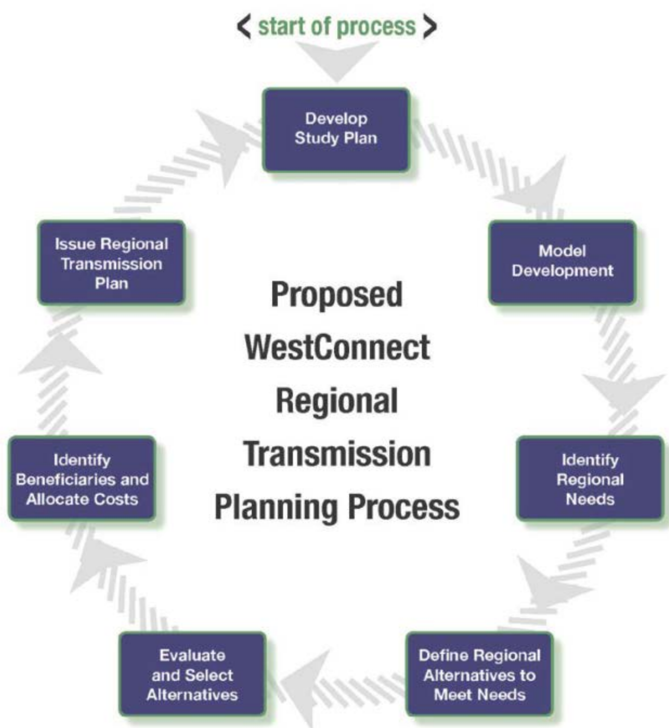
[9] WestConnect, "WestConnect Planning Participation Agreement," Section 5.2, November 17, 2014.
[10] Link to the PPA: http://www.westconnect.com/filestorage/wc_planning_participation_agreement_filed_111714

provided by the other membership classes and funds paid by project proponents for planning study requests.[11] These costs are allocated among the TOLSO Members according to a formula that considers the total number of TOLSO Members and the proportion of each Member's annual energy in MWh delivered to the TOLSO Member's load residing in the WestConnect planning footprint relative to the total annual energy delivered to the combined load of all TOLSO Members residing in the planning footprint.

### 1.2.4 Order 1000 Regional Planning Process Overview

WestConnect's Order 1000 Regional Transmission Planning Process consists of seven primary steps as outlined in Figure 7 below.

**Figure 7: WestConnect Proposed Order No. 1000 Regional Transmission Planning Process**




*: **Source** WestConnect Regional Planning Process Business Practice Manual*

An approximate timeline for the completion of each of the seven steps in the regional planning process is provided in Figure 8. As illustrated, WestConnect's regional planning process is performed biennially, beginning in even numbered years.

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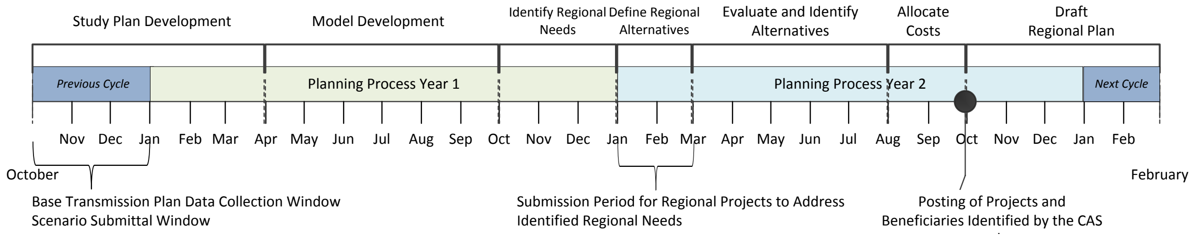
[11] Project proponents that submit a project for consideration in the WestConnect regional transmission plan, with the exception of merchant transmission project proposals, are required to submit a deposit of $25,000 to be applied toward the cost to study their project, and are subject to true-up based upon the actual cost of the study. Merchant transmission project proposals need not submit a study deposit when submitting their project into the WestConnect process, but the sponsor must still fully fund the study.

**Figure 8: WestConnect Regional Planning Process Timeline**




***Source**: APS Attachment E Exhibit 2*

Because WestConnect has only just initiated its first Order 1000 regional planning cycle, many details with regard to the implementation of the planning activities have yet to be defined. For this reason, in many cases, only general descriptions of WestConnect's proposed regional planning activities are provided in the subsequent sections. Furthermore, as previously highlighted, aspects of WestConnect's proposed regional transmission planning process are still under review by FERC, and as such are still subject to change. To the extent these aspects are described in the subsequent sections they are noted for the reader.

### 1.2.5 Sources of Planning Data and Assumptions

Data and assumptions used to create the regional power flow and production cost models used to perform the regional planning activities are derived from input provided by the PMC TOLSO Members, other TO participants within the WestConnect footprint, the WestConnect SPGs, from WECC data, and stakeholder input. WestConnect plans to coordinate planning data and assumptions with neighboring planning regions, but the process for doing so and discrete opportunities for requesting/incorporating neighboring planning region information are still to be identified. For the time being, modeling data and assumptions for areas outside of the WestConnect planning footprint are brought into the planning process via the WECC cases used as a starting point for the WestConnect planning models.

WestConnect's regional power flow models are created from WECC-approved base cases developed by the WECC Planning Coordination Committee (PCC). These cases are updated by the WestConnect SPGs for their planning footprint using input provided by the TOs within that footprint, to reflect the most recent planning assumptions of the TOLSO Members and TO participants and to be consistent with the study assumptions outlined in the WestConnect Regional Study Plan (e.g. with regard to the study year, loads, incremental resources, base transmission plan, etc.). Once updated, the SPGs provide the cases for their footprint to the PMC to be compiled into a regional power flow model. The compiled case is then reviewed and refined by the PS, the individual TOs, and the SPGs before it is approved by the PMC. Any changes made to the WECC base cases to create the WestConnect regional power flow models will be documented and reflected in the Regional Transmission Plan.

WestConnect will be creating a regional production cost model for the first time as part of its 2015 Regional Study Plan. WestConnect plans to use the WECC-TEPPC 2024 Common Case as a starting point to develop the regional production cost model. The data assumptions contained within the TEPPC dataset will be reviewed by WestConnect to determine what information may need to be updated to meet the study needs of the regional planning process. This effort is currently underway, but it is anticipated that WestConnect will seek any updates it requires from its TOLSO Members, TO participants, and stakeholders.

### *Base Transmission Plan*

The WestConnect regional base transmission plan is used to establish the base transmission network topology reflected in the regional power flow and production cost models that are analyzed to determine the regional transmission needs and to assess alternatives to meet those needs.

The base transmission plan consists of incremental transmission facilities expected to be on-line within the planning horizon as developed by the WestConnect TOLSO Members and TO participants in accordance with their local Order 890 planning processes. It includes any assumptions they may have made with regard to other incremental regional transmission facilities in the development of their plans. The base transmission plan may also include other projects under development by merchants or Independent Transmission Companies (ITCs) in the WestConnect planning region to the extent that there is sufficient certainty associated with these projects. Transmission projects selected for the purposes of cost allocation in previous regional planning cycles that are no longer subject to reevaluation are also noted to be included in the regional base transmission plan.[12]

To determine which incremental regional transmission facilities get included in the base transmission plan, WestConnect collects transmission project information using the TPPL it created for its Order 890 planning process. For any project to be included in the base transmission plan it must have a nominal system voltage of 100 kV or greater,[13] must be located within the WestConnect planning footprint or interconnected to the WestConnect planning region, and must have been studied in accordance with federal and state regulatory planning requirements and demonstrate performance compliant with NERC and WECC planning standards.

TO projects designated with a “planned” project status in the TPPL will be included in the base transmission plan. As defined by WestConnect, planned facilities include projects that have a sponsor, have been incorporated in an entity’s regulatory filings, have an agreement committing entities to participate and construct, or for which permitting has been or will be sought.

Merchant/ITC-funded projects may be considered in the development of the base transmission plan to the extent that there is sufficient certainty associated with these projects. Project information submitted into the TPPL by a project sponsor is used by WestConnect to assess the likelihood of the project being in service in the relevant study timeframe, and therefore whether it is appropriate for inclusion in the regional base transmission plan. WestConnect developed a list of criteria used to establish this likelihood, starting with the criteria used by TEPPC for developing its Common Case Transmission Assumptions. WestConnect’s criteria list also considers construction status, a series of

[12] Any project selected for inclusion in the WestConnect Regional Transmission Plan will be reevaluated until state and federal approval processes have been completed, all local, state, and federal siting permits have been approved, and major construction contracts have been issued.

[13] Transmission facilities of a lesser nominal system voltage may still be included in the WestConnect power flow and production cost models, but will not be identified individually in the base transmission plan.

financial and implementation indicators, whether a system impact study has been performed on the project, and whether the project was assumed in-service for the purposes of a TOLSO Member's local planning process. As a final step, all projects that are recommended for inclusion in the WestConnect base transmission plan undergo a final review by the PMC, which reserves the right to exclude projects on an individual basis.

A more complete description of the criteria used to identify projects for inclusion in the WestConnect regional base transmission plan can be found in the WestConnect Regional Planning Process Business Practice Manual.

### 1.2.6 Scenario Analysis

WestConnect plans to perform scenario analysis as part of the regional planning process to evaluate regional transmission needs under alternative sets of assumptions from those used to develop the base case models.[14] Scenarios studied during the planning cycle will be identified by the PMC and through an open season stakeholder request window as illustrated in Figure 8.

In the event that the number of scenario requests made to WestConnect exceeds the region's capability to evaluate them in a given planning cycle, or a request is determined to be out of the scope of the regional planning process, WestConnect will inform the requesters of this determination in the course of developing the draft Regional Study Plan. If a scenario request is omitted from the draft Regional Study Plan, it may still make its way into the final Regional Study Plan if the requestor petitions the PMC to reconsider the request, commits to fund the cost to study the scenario, and the PMC approves the request. WestConnect has not stated a commitment to study a minimum number of scenarios in each planning cycle.

WestConnect may develop scenario requests for submittal to the WECC-TEPPC process.

### 1.2.7 Consideration of Public Policies

WestConnect intends to reflect enacted public policies as it rolls local TO plans into the regional planning models, but a general process description for documenting these enacted public policies has not been defined. WestConnect does plan to perform a gap analysis as part of its 2015 Regional Study Plan to ensure that adequate renewable resources are included in the regional models so as to comply with enacted RPS requirements. Non-enacted or proposed public policies will be handled as part of the scenario analysis process described above.

[14] WestConnect's BPM notes that alternative assumptions that may be considered in the scenario analysis could include, but are not limited to, those related to demand forecasts, generation additions and retirements, or transmission infrastructure changes. Non-transmission Alternatives may also be considered in future scenarios such as a change in Distributed Generation (DG) and/or Demand Side Management (DSM) (Energy Efficiency [EE], Demand Response [DR]) or changes to public policy considerations.

### 1.2.8 Project Submittal and Evaluation Process

WestConnect will accept transmission projects (seeking cost allocation or not), and non-transmission alternatives submitted by active WestConnect members in good standing in response to identified regional needs posted to the WestConnect website through Quarter 5 of the regional planning process.

#### *Project Submittals*

In order to qualify as a valid project submittal, the submitter must identify the regional need that the proposed project is intended to remedy. Projects submitted for consideration must also connect to more than one TO and/or must be expected to show benefit to more than one TO. All data, applicable deposits for study costs, and other project information requested by WestConnect must be provided before the project will be studied.[15] If a proposal does not meet the applicable criteria for a valid project submittal, the project will not be evaluated in the current cycle of the transmission planning process.

#### *Regional Reliability, Economic, and Public Policy Needs*

Regional transmission needs are categorized as reliability, economic, or public policy-based needs.

**Reliability:** Needs are identified through the regional reliability assessment run on the regional power flow model(s). The scope of these assessments will be defined in the Regional Study Plan, and may include steady-state power flow, voltage, stability, short circuit, and transient studies. If a single-system reliability violation is identified as part of this power flow evaluation, the violation will be referred back to the appropriate TO for resolution. In the event that a simulated outage produces violations in more than one TO's system, that violation will result in the identification of a regional reliability need.[16]

**Economic**: WestConnect will use production cost modeling to analyze whether there are projects that have the potential to reduce the total delivered cost of energy by alleviating congestion or providing other economic benefits to the transmission system located within the WestConnect planning footprint.[17] The metrics that will be used to establish a regional economic need have not yet been defined.

**Public-Policy**: WestConnect will identify public policy requirements that are driving local transmission needs of TOLSO Members such that those requirements can be directly included in the regional power flow and production cost models. WestConnect then proposes to seek stakeholder input to identify regional transmission needs driven by public policy requirements. It will evaluate selected needs for regional solutions, considering factors such as the feasibility of addressing the need in the current planning cycle.

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[15] WestConnect's most recent round of compliance filings addressed compliance directives from FERC regarding the information submittal requirements set forth for merchant developer project sponsors. WestConnect's tariff revisions in response to the FERC directives are pending.

[16] WestConnect, "Regional Planning Process Business Practice Manual", Version 14.1, July 1, 2014.

[17] APS Attachment E Section III.E.3

### *Identifying Solutions for Regional Transmission Needs*

Projects proposed based on reliability-, economic-, or public policy-based needs respectively must be found to address the identified need. WestConnect will select the most efficient or cost effective regional transmission solutions or non-transmission alternatives among proposals by taking into consideration factors such as: their relative costs, implementation risks, reliability impacts, construction timelines, and project benefits and costs within the planning timeframe.

Projects seeking cost allocation that have been shown to meet an identified regional need and have passed the applicable cost allocation benefit-cost thresholds set by WestConnect will be further reviewed by the PMC and the individual beneficiaries to determine if the project will be granted a regional cost allocation. WestConnect's cost allocation process and specifically the process whereby the CTO members can elect to accept or not the proposed cost allocations for a project are aspects of the WestConnect regional planning process currently under review by FERC.

### *No Obligation to Construct*

The WestConnect regional planning process will identify the more efficient or cost-effective transmission solutions for the planning footprint. However, the regional planning process does not obligate any entity to commit to construct any facilities regardless of whether those facilities have been included in the WestConnect regional transmission plan.[18]

## 1.2.8 WestConnect 2015 Study Plan

WestConnect's Order 1000 Regional Transmission Planning Process commenced on January 1, 2015. Because the process is beginning in an odd-numbered year, WestConnect opted to conduct an abbreviated one-year regional planning cycle in 2015, and to begin its first full biennial planning cycle beginning in 2016.

Despite the abbreviated cycle, all of the activities contemplated in the full biennial planning process (Figure 7) are reflected in the 2015 Regional Study Plan; however, the scope of each of these activities is limited to provide WestConnect the opportunity to address all aspects of its planning process in a one-year timeframe.

As part of its 2015 Regional Study Plan, WestConnect plans to construct a single 10-year, 2024 heavy summer regional power flow case[19] and to use that case to perform an evaluation of N-1 contingencies to verify compliance with North American Electric Reliability Corporation (NERC) TPL standards for N-1 outages. Specifications for this case with regard to the load, resources, and transmission assumptions were specified in the 2015 Regional Study Plan as follows:

- Forecast loads included in the reference case will be based on the 2024 base load forecast developed by each TO Member and should include the impact of planned energy efficiency, demand side management programs, and behind-the-meter distributed generation resources.

[18] APS Attachment E Section VII.B.10
[19] This case will be developed from the 2024hs1 WECC-PCC power flow base case.

- The reference case will include adequate generation resources to meet the forecast load plus reserve requirements. Adequate renewable resources will be included to meet the RPS requirements for each Member TO. Generation modeled should include all existing, under construction, and planned generation that have received regulatory approval.
- The reference case will include all existing facilities, facilities that are under construction, and planned transmission facilities included in the 2015 WestConnect Annual Ten-Year Transmission Plan and approved for inclusion in the regional models by the PMC (as outlined in the base transmission plan.)

For 2015, WestConnect's reliability analyses will be limited to steady state system performance. The reliability studies will be performed using the PowerWorld Simulator modeling tool. WestConnect has requested that the WECC-PCC construct a 10-year light load case as part of the PCC 2015 Annual Study Program so that the region, as well as the other Western Planning Regions, can use this case in support of their regional planning activities next year.

The scope of WestConnect's activities with regard to economic modeling in 2015 is limited. WestConnect plans to review the WECC-TEPPC 2024 Common Case and determine what portions of the data set should be updated to meet the needs of the regional planning process. Changes will then be made to the TEPPC dataset with the goal of creating a 2024 WestConnect Regional Production Cost Model in the ABB GridView™ format. WestConnect hopes to then use this case to discern whether there are indications of congestion or other issues that might indicate regional economic needs, and will also look to establish a methodology for the assessment of economic needs to be approved for use in its first full biennial planning cycle commencing in 2016.

The analysis of transmission needs driven by public policy requirements conducted in 2015 will be limited to needs driven by renewable portfolio standard (RPS) requirements. WestConnect will perform a gap analysis to ensure that adequate renewable resources are included in the regional models so as to comply with enacted RPS requirements. The regional power flow and production cost models created by WestConnect (to the extent they are available) will then be used to evaluate if adequate transmission facilities are available to access the renewable resources and thereby achieve RPS public policy.

It was not anticipated that any scenarios would be developed or analyzed by WestConnect in 2015 due to the abbreviated nature of its first regional planning cycle. However, the 2015 Regional Study Plan does note that, time permitting, WestConnect may develop a coal reduction scenario to evaluate potential transmission needs associated with the EPA's proposed Clean Power Plan using power flow tools.

WestConnect plans to collect alternatives to meet any identified regional needs resulting from the technical studies described above, and to conduct the remaining planning activities outlined in its complete regional planning process to the extent that there are needs identified, projects submitted to meet those needs, and requests for cost allocation. WestConnect also plans to use 2015 to continue developing the implementation details of its regional planning process so they are ready for the first biennial planning cycle to start in 2016.

### 1.2.9 WestConnect SPG Activities

The WestConnect SPGs conduct independent studies for their subregional planning footprint. The studies contribute to the ten-year transmission plans of the member TOs, which are collectively used to provide input into the WestConnect regional planning process. The SPGs also provide planning support to WestConnect: for example, as part of WestConnect's 2015 Regional Study Plan, each of the WestConnect SPGs is responsible for updating the 2024hs1 WECC-PCC power flow base case — selected as the starting case for the WestConnect regional power flow model — for their subregional planning footprint. The SPGs will provide support to WestConnect throughout the regional planning process through the review of models and results from the reliability and economic assessments.

Organized within each WestConnect SPG are subcommittees established to focus on specific geographic areas of the SPG footprint, as well as work groups and task forces established to conduct specific planning activities for the entire SPG footprint. For example, the TPL Studies Work Group within CCPG coordinates analyses of transmission system performance for CCPG members and assists CCPG member transmission planners in complying with NERC Reliability Standards TPL-001 thru 004 as well as TPL-001-WECC-CRT-2.1. The work group analysis typically includes an assessment of load flow, transient stability, and voltage stability of both near term (one to five-year timeframe) and longer term (six to ten-year timeframe) transmission system conditions. CCPG provides a forum for the Colorado utilities under the jurisdiction of the Colorado Public Utilities Commission (CPUC) to coordinate technical studies needed to develop joint 10- and 20-year transmission plans that are required to be filed with the CPUC as part of CPUC Rule 3627.[20] Within SWAT, the California Interface Working Group was established to improve coordination between the SWAT and California transmission planning processes and to provide input to California's transmission planning processes that benefit SWAT members. In 2014, this group reviewed results of the CAISO transmission planning process and reported developments to the rest of SWAT.

Also in 2014, SWAT created a Coal Reduction Assessment Task Force for the purpose of identifying and assessing the transmission reliability concerns that could result from a large amount of upcoming coal plant capacity reduction in the Southwest. Phase 1 of the group's efforts was completed in 2014 and consisted of power flow and transient stability assessments of a variety of coal reduction scenarios that assumed replacement by both gas and renewable resources. From its analysis, the group concluded that there was a limit to the amount of coal capacity that could be reduced while maintaining reliable system operation, but that limit is influenced by the amount of gas fired replacement capacity that is added to the system. They also concluded that the amount of renewable resources that could be integrated in place of the retired coal capacity is dependent upon the addition of gas fueled generation or other resources that compensate for the loss of inertia and dynamic reactive capability.[21] The group plans to continue with a Phase 2 to their assessment in 2015 that will measure transmission system reliability performance under different scenarios reasonably projected by the proposed EPA Clean Power Plan. It will also respond to the Arizona Corporation Commission's Order for jurisdictional TOs to

[20] CPUC Rule 3627 was adopted in 2011 and required the Commission-regulated utilities to establish a process to coordinate the planning of transmission in Colorado on a state-wide basis and in a comprehensive, transparent, stakeholder-driven manner.

[21] SWAT Coal Reduction Assessment Task Force, Presentation to TEPPC, August 13, 2014.

jointly produce a study to identify minimum transmission system requirements within Arizona to maintain reliability in light of coal retirements.[22]

## 1.3 Planning Coordination

WestConnect facilitates quarterly meetings of the SPGs operating within its planning footprint, and a joint SPG meeting is held in August. The purpose of these meetings is to promote effective, open, and transparent collaborative transmission planning within and among the subregions of the WestConnect Planning Area.[23] During the August Joint Meeting, each SPG presents a summary of its transmission planning efforts as well as major projects under development in each SPG and information for each WestConnect member's TTC/ATC.

WestConnect members participate in many of the committees and work groups at WECC, but WestConnect does not have formal membership on any WECC committee. Rather, it is the WestConnect SPGs (SWAT, SIERRA, CCPG) that hold membership at both the Regional Planning Coordination Group and Transmission Expansion Planning Policy Committee – where other Regional Planning Groups also maintain a membership seat. WestConnect, with the support of its SPGs, requested that the individual SPG representation on TEPPC be replaced by a single WestConnect membership seat to more closely align with the membership representation of the other Western Planning Regions. This request is currently under consideration by WECC and will require WECC Board approval.

WestConnect is currently engaged with the other three Western Planning Regions to define the Interregional (IR) Coordination process approved by FERC on December 18, 2015. More details regarding these IR Coordination activities are provided later in this report. For the time being, in their 2015 Regional Study Plan, WestConnect plans to coordinate with the Western Planning Regions by participating in interregional coordination meetings, distributing the final approved 2015 Regional Study Plan, sharing planning data and models if and when requested, and requesting modeling data from TOs in neighboring planning regions during the development of regional models.[24]

## 1.4 Stakeholder Process

WestConnect and its SPG meetings are open to all interested parties, with the exception of closed sessions authorized under the terms of the WestConnect PPA. All regional planning meetings, including SPG meetings, are noticed on the calendar accessed through the WestConnect website (www.WestConnect.com).

WestConnect held an open stakeholder meeting on February 19, 2015 to provide an overview of their Order 1000 regional planning process. Open stakeholder meetings are tentatively scheduled for July and November to share identified regional needs and the draft Regional Transmission Plan with stakeholders. Going forward, WestConnect will hold open stakeholder meetings at least on a semi-annual basis.

[22] WestConnect, "2015 Annual Ten-Year Transmission Plan", February 19, 2015.
[23] WestConnect, "2015 Regional Study Plan", January 6, 2015.
[24] ibid.

WestConnect has notified stakeholders that they will be invited to comment on various aspects of the regional planning process through direct participation in the subcommittee and work group meetings, and through open comment periods for various outputs of the process including: the Regional Study Plan, evaluation of alternative transmission solutions, evaluation of public policy requirements, and the draft Regional Transmission Plan.[25]

## Links to Key Documents

2015 WestConnect (Order 890) Annual Ten-Year Transmission Plan

WestConnect 2015 Regional Study Plan

WestConnect Regional Planning Process Business Practice Manual

WestConnect Planning Participation Agreement

WestConnect Regional Compliance Filings

[25] WestConnect Regional Planning Process Stakeholder Meeting presentation, February 19, 2015.

# Chapter 2: Northern Tier Transmission Group

The Northern Tier Transmission Group (NTTG) is an unincorporated association of transmission providers and customers working collaboratively with state representatives and other stakeholders to perform regional transmission planning and to increase the efficient use of the power grid that delivers electricity to customers in the Pacific Northwest and Mountain States of the Western Interconnection. The Northern Tier Transmission initiative was announced in the fall of 2006 to carry out coordinated subregional planning, common assured transfer capability methods and coordination, and a diversity interchange for area control errors.[26] NTTG was subsequently formed in 2007 from the Northern Tier initiative to fulfill the requirements set forth by FERC Order 890 that local transmission providers participate in regional and sub-regional planning efforts.[27] NTTG now serves as the transmission planning region for compliance with Order 1000 by its participating utilities.

### *NTTG Highlights*

- NTTG is the only Region to utilize a "round-trip" approach to conducting its technical studies whereby they identify hours of stressed system conditions using a production cost model and export information from those hours to study them further using power flow tools.
- The Region's public utility Transmission Providers received a final Order from FERC on March 24, 2015 fully accepting their fourth round of tariff revisions addressing the regional requirements of Order 1000.

## 2.1 Planning Footprint

The transmission systems of the participating utilities[28] comprising NTTG are illustrated in Figure 7, and reflect the NTTG regional transmission planning footprint.

[26] NTTG, "2007 Annual Planning Report", April 2, 2008.

[27] NTTG Transmission Providers' Order 890 compliance filing used the term "sub-regional" to refer to NTTG and "regional" to refer to the Western Electricity Coordinating Council ("WECC"). In other places within this document "region" refers to NTTG, WestConnect, ColumbiaGrid, or CAISO. WECC is an interconnection-wide entity.

[28] The term "participating utilities" is used to refer to the signatories to the NTTG Funding Agreement.

Figure 9: NTTG Regional Planning Footprint


***Source**: NTTG*

NTTG's planning footprint encompasses the transmission systems of the participating utilities listed in Table 3 and spans all or portions of seven Western States including: California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah. The systems of these transmission providers collectively span more than 29,000 miles, and serve over 4 million retail customers.[29]

Table 3: NTTG Participating Utilities

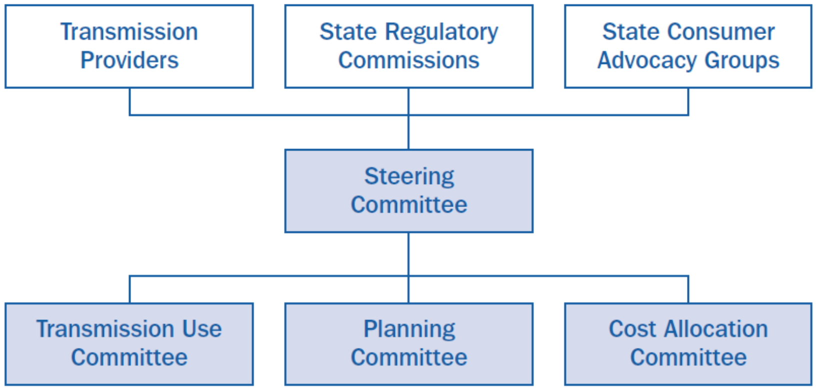
| |
|---|
| Deseret Generation & Transmission Co-operative |
| Idaho Power |
| NorthWestern Energy |
| PacifiCorp |
| Portland General Electric |
| Utah Association of Municipal Power Users |

## 2.2 Standing Committees and Membership

The activities performed by NTTG are governed by agreement and charters of committees. NTTG has four standing committees which include: the Steering Committee, the Planning Committee, the Cost Allocation Committee, and the Transmission Use Committee. Overall planning direction is provided by the Steering Committee. The structure of the NTTG standing committees is illustrated in Figure 8.

[29] http://nttg.biz/site/index.php?option=com_content&task=blogsection&id=18&Itemid=88

**Figure 10: Structure of NTTG Standing Committees**




***Source**: NTTG 2012-2013 Biennial Transmission Plan Summary*

Each committee operates pursuant to a charter which outlines its purpose, limitations, membership classes, and governance. The roles of each NTTG standing committee and their membership classes are summarized below.

### 2.2.1 Steering Committee

**Responsibilities**

- Provides governance and direction on the initiatives undertaken by the NTTG members
- Provides a forum for facilitating dispute resolution
- Approves the final Regional Transmission Plan

**Membership Classes**

- Class 1 - Utility Cooperatives and Utilities which are a party to the NTTG Funding Agreement
- Class 2 - State utility commissions, state customer advocates, or state transmission siting agencies within the NTTG footprint

### 2.2.2 Planning Committee

**Responsibilities**

- Prepares the Regional Transmission Plan
- Conducts regional economic studies requested by stakeholders
- Reports to the Steering Committee

**Membership Classes**

- Class 1 – Transmission Providers or Transmission Developers engaged in, or intending to engage in, the sale of electric transmission service within the NTTG footprint
- Class 2 – Transmission Users engaged in the purchase of electric transmission service within the NTTG footprint

- Class 3 - State utility commissions, state customer advocates, or state transmission siting agencies within the NTTG footprint
- Signatories to the NTTG Funding Agreement are automatically members of the PC. Stakeholders seeking to join the PC as a member of Class 1 or Class 2 do so by executing the Planning Committee Membership Agreement. Regulators can request committee membership via a transmittal letter to NTTG.

### 2.2.3 Cost Allocation Committee

**Responsibilities**

- Applies NTTG's cost allocation principles and practices
- Develops cost allocation recommendations for transmission projects selected into NTTG's biennial Regional Transmission Plan for purposes of cost allocation
- Reports to the Steering Committee

**Membership Classes**

- Class 1 – Parties to the NTTG Funding Agreement that have appointed a representative to the Steering Committee
- Class 2 - State utility commissions, state consumer advocates, or state transmission siting agencies within the NTTG footprint that have appointed a representative to the Steering Committee. Membership in Class 2 is requested via a transmittal letter to NTTG.

### 2.2.4 Transmission Use Committee

**Responsibilities**

- Increase the efficiency of the existing member utility transmission systems through commercially reasonable initiatives, and
- Increase customer knowledge of, and transparency into, the transmission systems of the member utilities

**Membership Classes**

- Class 1 - Parties to the NTTG Funding Agreement
- Class 2 - State utility commissions, state customer advocates within the NTTG footprint. Membership in Class 2 is requested via a transmittal letter to NTTG.

Standing committee members as of March 1, 2015 are listed in Table 4.

Table 4: Members of NTTG Standing Committees as of 3/1/15

| NTTG Member | Steering Committee | Planning Committee | Cost Allocation Committee | Transmission Use Committee |
|---|---|---|---|---|
| Absaroka Energy, LLC | | ● | | |
| Avista Corporation | | ● | | |
| Black Hills Power[1] | | ● | | |
| Deseret Power Electric Cooperative | ● | ● | ● | ● |
| Gaelectric, LLC | | ● | | |
| Idaho Office of Energy Resources | | ● | | |
| Idaho Power | ● | ● | ● | ● |
| Idaho Public Utilities Commission | ● | ● | ● | |
| Montana Consumer Council | ● | | ● | |
| Montana Public Service Commission | ● | ● | ● | |
| NorthWestern Energy | ● | ● | ● | ● |
| Oregon Public Utility Commission | ● | | | |
| PacifiCorp | ● | ● | ● | ● |
| Portland General Electric | ● | ● | ● | ● |
| Sea Breeze Pacific[1] | | ● | | |
| TransCanada | | ● | | |
| UAMPS | ● | ● | ● | |
| Utah Office of Consumer Services | ● | | ● | |
| Utah Public Service Commission | ● | ● | ● | |
| Wyoming Office of Consumer Advocates | | | ● | |
| Wyoming Public Service Commission | ● | ● | ● | |

[1] Committee member with no appointed voting representative

Stakeholders may participate in public Steering, Planning, and Cost Allocation Committee meetings, however, only those stakeholders that satisfy the criteria of a membership class are eligible to vote during committee meetings. The Transmission Use Committee holds a public stakeholder meeting at least twice per calendar year.

NTTG has hired an independent staff to provide third-party project management and planning facilitation services. NTTG's initiatives, including their regional planning activities, are undertaken by staff of the NTTG participating utilities and other members of the standing committees.

## 2.3 Funding for Regional Planning Activities

NTTG's participating utilities collectively share funding obligations for NTTG initiatives, including regional transmission planning activities. These utilities have executed the NTTG Funding Agreement which defines their rights and obligations, including a funding allocation methodology. Two categories of funding parties are defined: Nominal Funders and Full Funders:[30]

**Eligibility to become a Nominal Funder**

- Non-public utility transmission dependent utility;
- Will participate in the Northern Tier planning process; and
- Has either electric load, electric generation, or both, which is interconnected with an existing Full Funder or which is located within the balancing authority area of an existing Full Funder.

**Eligibility to become a Full Funder**

- Owns, controls, or operates a facility used for transmission and interconnected with an existing Full Funder or which is located within the balancing authority area of an existing Full Funder; and
- Will utilize Northern Tier planning processes or services to meet transmission planning and cost allocation requirements set forth in the FERC's Order 890, Order 1000, or related successor regulations or orders for its transmission facilities located within the Western Interconnection.

Nominal Funders are required to contribute a fixed amount[31] toward the annual NTTG budget. The funding obligation of Full Funders is the same fixed amount plus an additional share of the annual NTTG budget based on the entity's total transmission service plus net energy for load (MW), the number of parties to the Funding Agreement, the number of Full Funders, and the entity's proportional share of net energy for load relative to the total net energy for load of the NTTG footprint. All of the participating utilities listed in Table 2 are Full Funders, with the exception of the Utah Association of Municipal Power Users (UAMPS), a public power organization, which is a Nominal Funder.

## 2.4 Order 890 Regional Transmission Planning

Execution of NTTG's first biennial planning process began in January of 2008, and the first NTTG Biennial Transmission Plan report was issued in November of 2009. This plan established the baseline transmission system configuration capable of reliably meeting the identified needs for the NTTG footprint for a ten-year planning horizon.

NTTG's Cost Allocation Committee has prepared a final report in conjunction with the Biennial Transmission Plan report since 2009. This report details any recommendations made by the committee with regard to the cost allocation for projects studied as part of the biennial planning process. While the committee was specifically tasked with making recommendations on cost allocations for projects

[30] NTTG, "Amended Northern Tier Transmission Group Funding Agreement".
[31] This fixed amount is $17,000 for the funding term of January 1, 2014 through December 31, 2015.

considered within the planning process, it looked to project developers and sponsors to provide detailed data, analyses, and studies sufficient for the committee to make its recommendations with respect to proposed benefit and cost allocations and the adherence to NTTG's cost allocation principles.[32] The committee did not perform independent analyses of a project's benefits and beneficiaries, nor a cost allocation based upon distribution proportionate to benefits.

As part of the 2008-2009 planning cycle, the Cost Allocation Committee compiled and considered cost allocation information for sixteen transmission projects that were studied as part of the biennial planning cycle. Of these sixteen projects, the committee developed recommendations for the cost allocation of ten projects. In subsequent planning cycles the committee was either unable to obtain sufficient information from project sponsors to demonstrate consistency with NTTG's cost allocation principles, or no requests for NTTG cost allocation were submitted. As such, no recommendations were made regarding the cost allocation for projects presented in the 2010-2011 or 2012-2013 Biennial Transmission Plan reports.

## 2.5 NTTG Order 1000 Regional Transmission Planning

NTTG's public utility TOs have filed four rounds of regional compliance filings with FERC. The most recent filings were made on December 30, 2014,[33] in response to FERC's third regional order issued on December 8, 2014. In this third regional order, FERC required the NTTG public utility TOs to make two minor changes to their respective Open Access Transmission Tariffs (OATTs) to more fully address compliance directives in its second regional order.

In its first compliance order issued in May of 2013, FERC accepted an October 1, 2013 effective date of the NTTG public utility TOs' revised Attachment Ks to their OATTs, which outlines the details of the regional transmission planning process developed to comply with Order 1000. As such, the 2014-2015 biennial planning cycle, which commenced in October 2013, marks the first planning cycle conducted in accordance with FERC Order 1000.

On March 24, 2015 FERC fully accepted NTTG's Order 1000 OATT revisions submitted on December 30, 2014, making NTTG the second western Planning Region to fulfill all of the compliance obligations with regard to the regional planning requirements of Order 1000.

### 2.5.1 Planning Process Overview

NTTG's regional transmission planning process is performed over eight quarters, beginning in January of even numbered years. The planning activities conducted in each quarter of the biennial planning cycle are outlined in Figure 9.

[32] NTTG, "Cost Allocation Principles Report", May 29, 2007.
[33] Regional Compliance Filings filed by the NTTG public utility TOs in response to FERC Order 1000 can be accessed here: http://nttg.biz/site/index.php?option=com_content&task=view&id=350&Itemid=105.

Figure 11: NTTG Eight-Quarter Biennial Planning Process

| Biennial Planning Cycle | | | | Economic Study Request Cycle | | |
|---|---|---|---|---|---|---|
| Gather Information | * | 01 | Year One | Receive Requests | * | 01 |
| Develop Study Plan, Assumptions | * | 02 | | Develop Study Plan | * | 02 |
| Perform Draft Plan Analysis | * | 03 | | Perform Studies | | 03 |
| Perform Draft Plan Analysis | * | 04 | | Report and Review | * | 04 |
| Draft and Review Report and Gather Info | * | 05 | Year Two | Receive Requests | * | 5 |
| Final Plan Analysis and Cost Allocation | * | 06 | | Develop Study Plan | * | 6 |
| Prepare and Review Final Report | * | 07 | | Perform Studies, Prepare and Review Final Report | * | 7 |
| Obtain Final Plan Approval | | 08 | | | | |

* Stakeholder Input

***Source**: NTTG Regional Planning and Cost Allocation Practice document*

As illustrated, economic study requests are accepted by NTTG during both Quarter 1 and Quarter 5 of the biennial planning cycle. NTTG will perform up to two regional economic study requests per biennial planning cycle. To determine which study requests are performed, NTTG evaluates the requests based on input from stakeholders and the opportunity for the request to reduce overall costs of the Regional Transmission Plan while reliably serving load growth needs. Additional regional economic study requests may be completed at the expense of the requester.

The Draft Regional Transmission Plan is produced by the end of Quarter 4, at which time stakeholders have an opportunity to review and comment on the draft plan. NTTG may revise its Biennial Study Plan in Quarter 5 based on the Planning Committee's review of stakeholder comments and any updates received regarding the load, resource, or transmission project assumptions or data originally submitted in Quarter 1 and used to perform technical studies. The Final Regional Transmission Plan is approved by the Steering Committee by the end of Quarter 8.

### 2.5.2 Sources of Planning Data and Assumptions

The first step of each NTTG regional transmission planning cycle is to gather the data and assumptions that will be used to perform the technical studies supporting the regional transmission plan. The participating utilities provide NTTG with the following information in Quarter 1, including:

- Their local transmission system plan;
- Data used to develop their local plan including projections of customer loads[34] and resources, projected transmission service forecasts, and existing and planning demand response resources;

[34] The 2014-2015 NTTG Biennial Study Plan notes that load forecasts submitted to NTTG are generally those in the participating utility's official load forecast and are similar to the load forecasts provided to the Loads and Resource Subcommittee of the WECC PCC. No explanation was provided for any differences that may exist between the load forecasts submitted to NTTG by the participating utilities and the forecasts they submit to WECC.

- Information regarding new or changed circumstances or data contained within their local transmission plan;
- Public policy requirements;
- Public policy considerations; and
- Any other project proposed for the Regional Transmission Plan.

In addition, any stakeholder may submit data to be evaluated as part of the planning process via either the NTTG Data Submittal Form[35] or via email directly to NTTG.

### 2.5.3 Initial Regional Transmission Plan

The Initial Regional Transmission Plan (IRTP) is a combination of the NTTG participating utilities' local transmission plans and regional transmission projects selected in prior regional planning cycles. The IRTP is developed in Quarter 3 and is expected to provide for the reliable delivery of power to all regional loads taking into account the perspective of each participating utility.

Loads, resources and transmission inputs from the IRTP are incorporated into WECC base case models that are in turn used as a starting point for NTTG's reliability and economic studies. NTTG has chosen to use the WECC TEPPC production cost model dataset as a starting point for its technical studies.

For the 2014-2015 planning cycle, NTTG reviewed the load, resource, and transmission data contained within the TEPPC 2024 Common Case dataset to ensure that the representations were reasonably close to the data that the participating utilities submitted in Quarter 1 of the biennial planning cycle. Some differences were noted, but NTTG accepted the TEPPC 2024 Common Case dataset as a reasonable representation of the IRTP based on the work TEPPC had done to incorporate the latest planning information from all the western utilities, including those outside of the NTTG planning footprint. As such, the TEPPC 2024 Common Case dataset is being used to perform NTTG's 2014-2015 reliability and economic studies.

### 2.5.4 Project Submittals

Also during Quarter 1 of the biennial planning cycle, incumbent transmission developers, nonincumbent transmission developers (including other stakeholders), and merchant transmission developers may submit transmission projects for consideration in the Regional Transmission Plan.[36] Projects submitted by stakeholders are referred to as "unsponsored projects." Varying degrees of information regarding the proposed project are required to be submitted to NTTG depending on whether the submitter is an incumbent transmission developer or other entity. In addition, stakeholders are not required to submit the full scope of information required by NTTG for complete project submittals if they wish to simply submit an idea for consideration in the planning process. Stakeholders may submit ideas into the regional planning process simply by email to NTTG.

[35] Link to NTTG Data Submittal Form:
http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=2100&Itemid=31

[36] Both transmission and non-transmission alternatives are submitted using the same submittal form.

Projects wishing to be submitted for consideration in the Regional Transmission Plan for the purposes of cost allocation are required to fill out and submit a Cost Allocation Data Form.[37] In addition, a project sponsor interested in submitting a project for cost allocation must submit pre-qualification data before the end of Quarter 8 of the preceding biennial planning cycle. Only those project sponsors that have pre-qualified for cost allocation will be allowed to submit a project for purposes of cost allocation into the NTTG biennial planning cycle.

### 2.5.5 Regional Plan Analysis

NTTG conducts a technical analysis of the IRTP to determine if modifications or additions — in the form of regional transmission projects or non-transmission alternatives as submitted in Quarter 1 or developed by the Planning Committee —will result in a Regional Transmission Plan that is more efficient or cost-effective than the IRTP.

The study techniques employed by NTTG include a combination of power flow and production cost modeling studies. Currently, NTTG uses the PowerWorld Simulator tool to evaluate transmission system reliability under normal and single contingency conditions, as well as under select N-2 contingencies identified by Peak Reliability. Production cost studies run using the ABB GridView™ production cost simulation tool are used to evaluate the range of production scenarios of interest in the planning cycle that may occur within the Western Interconnection. Results from NTTG's production cost studies are used to identify stressed hours for study using the power flow tool. NTTG then exports the load, resource, and transmission information from the production cost model for specific hours of study using the power flow tool.

NTTG is currently the only Region performing this round-trip approach to the technical studies in support of the regional planning process. WECC is investigating this approach for application in the TEPPC process, and is working with both NTTG and the GridView software developer on a way to automate the otherwise labor-intensive process.

#### *More Efficient or Cost Effective Regional Transmission Plan*

NTTG determines whether an alternative transmission or non-transmission project is more efficient or cost effective than the IRTP by utilizing those alternatives in one or more Change Cases. It compares the incremental cost of the Change Case against the capital-related cost for replaced or deferred projects from the IRTP that still allow for all regional transmission needs to be met. This evaluation of the IRTP and Change Cases is done using power flow analysis to first ensure that all system performance requirements and transmission needs driven by public policy requirements are met. If these needs are not met by a transmission or non-transmission alternative evaluated in a Change Case, NTTG may either set aside the alternative as unacceptable, or modify the Change Case with the addition of another alternative project.

[37] Link to NTTG Cost Allocation Data Form:
http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=2101&Itemid=31

For those Change Cases that meet the system performance requirements and transmission needs driven by public policy requirements, the incremental cost of the Change Case is derived from:[38]

- Annual capital-related costs of the project(s) evaluated in the Change Case;[39]
- The monetized value of the change in energy losses resulting from the project(s) evaluated in the Change Case; and
- The monetized value of the change in the annual reserve requirement for each balancing authority area within the NTTG Footprint as well as the reserve sharing quantity as a result of the project(s) evaluated in the Change Case.

The Change Cases are constructed by replacing non-committed projects in the IRTP with one or more of the alternative projects submitted in Quarter 1. A non-committed project is defined by NTTG as a project that does not have all permits and rights of way required for construction, as identified in the development schedule submitted for the project during the data gathering process conducted in Quarter 1 of the planning cycle. The set of projects from either the IRTP or Change Cases with the lowest incremental cost are incorporated into the Draft Regional Transmission Plan. If those projects are eligible for cost allocation, they will be evaluated for cost allocation by the Cost Allocation Subcommittee.

After stakeholder review of the Draft Regional Transmission Plan, and if new or updated planning information is provided to NTTG during Quarter 5 of the biennial planning cycle, the Planning Committee may revise the Biennial Study Plan and/or repeat the evaluation of the Change Cases used to inform the Regional Transmission Plan. The results of any additional analyses performed are used to inform the Final Regional Transmission Plan.

### *Scenario Analysis*

NTTG uses scenario analysis to address how uncertainty regarding future loads and resources or public policies under consideration may affect the regional transmission system. The results of these scenarios provide information regarding the potential performance and shortcomings of the Regional Transmission Plan. The results of these additional studies, however, are not used as direct inputs into or used to modify the Regional Transmission Plan.

Scenario analysis is also a component of the cost allocation process. In consultation with stakeholders, the Cost Allocation Committee will create allocation scenarios for those parameters expected to affect the amount of total benefits of a project and their distribution among beneficiaries. Variables tested in

[38] In the course of developing benefit metrics that would be used to identify the more efficient or cost-effective regional transmission solutions and for cost allocation purposes, NTTG investigated the applicability of a benefit metric reflecting changes in net production cost. It was the consensus of the cost allocation and production cost modeling work group that investigated the issue that the current production cost modeling framework does not provide sufficient accuracy to be used in the development of benefit metrics. See the NTTG report, “Evaluation of Production Cost Modeling for Transmission Cost Allocation,” August 30, 2013.

[39] NTTG uses the TEPPC Transmission Capital Cost tool to validate transmission costs submitted by project sponsors, or to develop the project capital cost estimates if sponsors do not submit project capital cost information.

the allocation scenarios may include load levels by load-serving entity and geographic location, fuel prices, and fuel and resource availability. The allocation scenarios are used so that the potential impact of key uncertainties can be estimated and incorporated in the calculation of net benefits used in the cost allocation process.

### *Consideration of Public Policies*

NTTG collects transmission needs driven by public policy requirements, public policy considerations, and associated data from the local transmission plans and stakeholders during the data gathering portion of the planning process (Quarter 1). NTTG's Regional Transmission Plan addresses transmission needs driven by public policy requirements, whereas public policy considerations are evaluated in consultation with stakeholders during the development of the Biennial Study Plan to determine if they create additional transmission needs to be evaluated as part of a scenario analysis. Results obtained from this scenario analysis are used as informational only: they will not result in the inclusion of any additional projects in the Regional Transmission Plan.

NTTG documents in its Biennial Study Plan and posts to its website the rationale for selecting or excluding transmission needs driven by public policy requirements and public policy considerations for evaluation as part of the regional planning process.

### 2.5.6 2014-2015 Biennial Planning Cycle

NTTG is currently in the process of concluding Quarter 5 of the 2014-2015 Biennial Planning Cycle, and has released its 2014-2015 Draft Regional Transmission Plan. This report details the technical studies performed by NTTG to-date, and the results of an analysis of the IRTP, IRTP without un-committed projects, and the evaluation of submitted alternatives.

NTTG selected five stressed-hours for study using power flow analysis based on the results of their production cost model study. The five hours selected for study reflect the following system conditions:

- maximum NTTG export;
- minimum NTTG export (import);
- maximum NTTG summer peak;
- maximum NTTG winter peak; and
- maximum flow from Montana to the Northwest (Path 8 in the WECC Path Rating Catalog).

In addition to studying the IRTP for these five stressed hours, NTTG created a series of Change Cases that consisted of removing non-committed projects from the IRTP and/or adding alternative projects submitted to NTTG in quarter 1 of the planning cycle. A summary of the future transmission projects being considered by NTTG in the 2014-2015 planning cycle is provided in Table 5.

**Table 5: Transmission Project Considered in the NTTG 2014-2015 Biennial Planning Cycle**

| Sponsor | Type | Projects | Voltage | Circuits |
|---|---|---|---|---|
| **Idaho Power (uncommitted)** | LTP | Gateway West Project | 500 kV | 2 |
| | LTP | B2H Project | 500 kV – 230 kV | 2 |
| **Great Basin Transmission (uncommitted)** | Sponsored (1) | Southwest Intertie Project North | 500 kV | 1 |
| **NorthWestern Energy** | LTP | Broadview – Garrison Upgrade | 500 kV | 1 |
| | LTP | Millcreek – Amps Upgrade | 230 kV | 1 |
| **PacifiCorp East (uncommitted)** | LTP | Gateway South Project | 500 kV | 1 |
| | LTP | Gateway West Project | 500 kV – 230 kV | 5 |
| **Portland General** | LTP | Blue Lake - Gresham | 230 kV | 1 |
| **TransWest Express (uncommitted)** | Merchant Transmission Developer (2) | TransWest Express | $\underline{+}$600 kV DC | 1 |

(1) Sponsored Projects and Unsponsored will be evaluated
(2) Per customer request, the TransWest Express (Merchant) project will not be evaluated this planning cycle as an Alternative Project for selection in the Regional Transmission Plan

***Source**: NTTG Steering Committee Meeting presentation, 3/9/2015*

Based on the reliability and economic results from the evaluation of the IRTP and Change Cases, NTTG determined that the most efficient and cost-effective plan is the Change Case plan consisting of the IRTP with all the non-committed projects removed and the addition of a new 500 kV line from Aeolus to Anticline to Populus (see 2014-2015 Draft Regional Transmission Plan in Table 6). This project was an unsponsored project introduced into the planning process by the Technical Work Group operating under the Planning Committee, and was developed to mitigate overloads observed in the Change Case consisting of the IRTP with the non-committed projects removed.

One project was submitted to NTTG for the 2014-2015 Biennial Planning Cycle requesting regional cost allocation: the Southwest Intertie Project – North (SWIP North). The sponsor for this project, Great Basin Transmission, was pre-qualified to seek regional cost allocation, but regional cost allocation is only performed on those projects selected in NTTG's Final Regional Transmission Plan. SWIP North was not identified in the 2014-2015 Draft Regional Transmission Plan.

**Table 6: NTTG 2014-2015 Draft Regional Transmission Plan**

| Sponsor | Type | Projects | Voltage | Circuits |
|---|---|---|---|---|
| NorthWestern Energy | LTP | Broadview – Garrison Upgrade | 500 kV | 1 |
| | LTP | Millcreek – Amps Upgrade | 230 kV | 1 |
| Portland General | LTP | Blue Lake - Gresham | 230 kV | 1 |
| TWG Identified Alternative | Unsponsored | Aeolus – Anticline - Populus | 500 kV | 1 |

***Source**: NTTG Steering Committee Meeting presentation, 3/9/2015*

Although the draft regional transmission plan meets the reliability and economic metrics set forth by the planning process, NTTG determined that reliability and economic analysis alone were not sufficient to show that the needs of the NTTG transmission system are being met in the ten year planning horizon. NTTG determined that other factors should be considered when identifying the regional transmission plan, including: contractual commitments, resource integration, transmission service requests (TSRs), and available transmission capability ("ATC") considerations. The 2014-2015 Biennial Study Plan is being modified to include the consideration of these factors in the development of the Final Regional Transmission Plan.

In the subsequent quarters of the planning cycle, NTTG plans to complete a robustness analysis of the draft Regional Transmission Plan using power flow and production cost analysis to ensure that the system performance requirements remain acceptable assuming deviations from the base case assumptions. NTTG plans to complete this analysis in Quarter 6 using input from stakeholders to define the deviations from base assumptions that are tested.

In addition to the robustness analysis, NTTG plans to conduct one scenario study based on requests received for public policy considerations to be studied in the biennial planning cycle. Three requests for public policy considerations were submitted to NTTG in the first quarter of the planning cycle. Of those three, NTTG determined one to be beyond the ten year planning horizon, and one to be a duplication of a scenario already studied by the WECC TEPPC. As such, NTTG plans to perform only the requested study involving the retiring of Colstrip units 1 and 2, and replacing the lost generation with Montana wind resources. The study will be performed using power flow analysis and using two of the five power flow base cases derived for the Regional Transmission Plan development: summer peak and Path 8 high flow cases. The results from this study will be used to inform the Final Regional Transmission Plan, but will not result in the inclusion of additional projects in the plan.

## 2.6 Planning Coordination

NTTG relies directly on the data collection, validation, and modeling work performed by WECC. NTTG and its members have been active participants in the WECC TEPPC process since TEPPC's inception, and have used the TEPPC datasets for their regional planning studies since their first biennial planning cycle conducted in 2008-2009.

NTTG is currently engaged with the other three Western Planning Regions to define the Interregional (IR) Coordination process approved by FERC on December 18, 2015. More details regarding these IR Coordination activities are provided later in this report.

## 2.7 Stakeholder Process

NTTG encourages stakeholders to participate in the development of the regional transmission plan throughout the biennial planning cycle. NTTG conducts regular Steering, Planning, and Cost Allocation Committee meetings that are open to stakeholders and allow for their direct input into the planning process. Dates, times, and locations of these meetings are posted to the NTTG website (http://nttg.biz).

In addition to attending open meetings, stakeholders are encouraged to submit requests for economic studies, provide input into the development of the Biennial Study Plan, participate through the Planning Committee to help identify regional transmission needs and corresponding solutions, and submit proposed transmission and non-transmission alternatives for consideration in the development of the regional transmission plan. This list is not exhaustive. Ongoing opportunities for stakeholder input are noticed on the NTTG website.

## 2.8 Links to Key Documents

Revised NTTG 2014-2015 Biennial Study Plan

2014-2015 Public Policy Consideration Study Plan

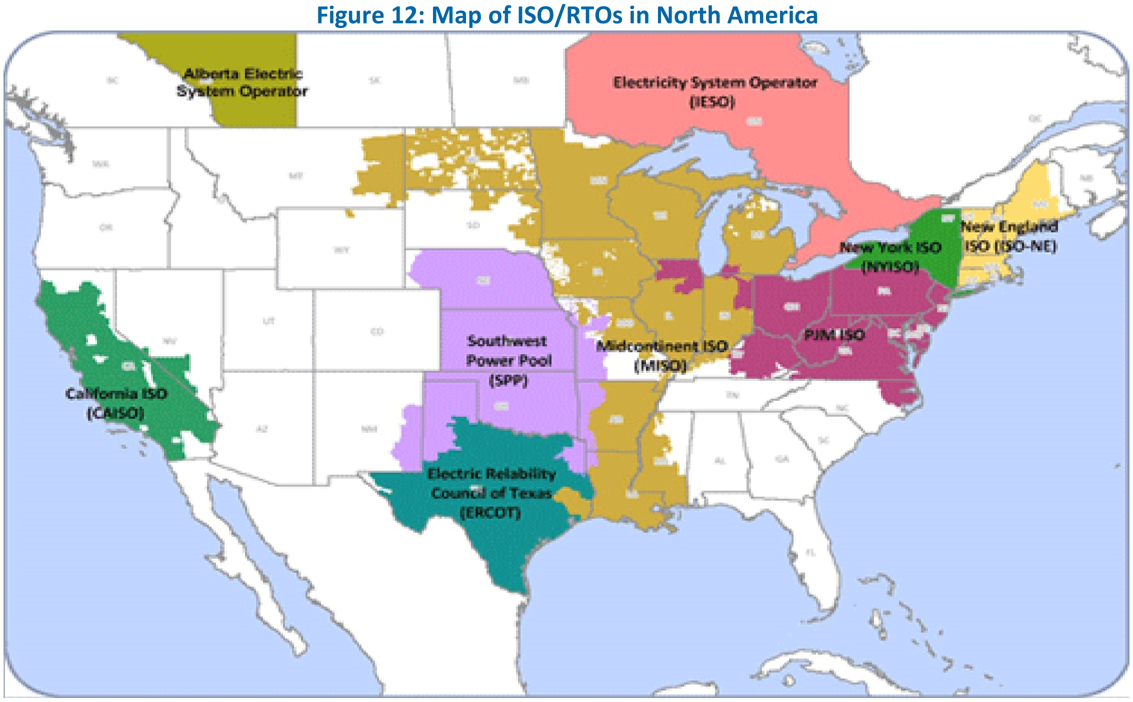
NTTG 2014-2015 Draft Regional Transmission Plan

NTTG Regional Compliance Filings

# Chapter 3: California Independent System Operator

The passage of the Energy Policy Act of 1992 paved the way for the introduction of competition in wholesale electricity markets, and the subsequent issuance of FERC Orders 888/889 led to the emergence of Independent System Operators (ISOs) to manage the wholesale markets and provide non-discriminatory access to transmission. FERC Order 2000 encouraged the formation of Regional Transmission Organizations (RTOs) to administer the transmission grid on a regional basis. Currently, there are seven ISO/RTO-type institutions in the U.S (in addition there are two ISO/RTOs in Canada). Out of the seven, the California Independent System Operator (CAISO) is the only ISO/RTO-type institution in the U.S. portion of the Western Interconnection. The remaining U.S. ISO/RTOs are based in the Eastern Interconnection and Texas ERCOT (Figure 12).

**Figure 12: Map of ISO/RTOs in North America**




***Source**: FERC*

Following the passage of the Energy Policy Act of 1992, the California Public Utilities Commission (CPUC) issued its Blue Book proposal to launch a process to restructure the regulation of electric utilities in California to allow for more competition. Subsequently, the passage of Assembly Bill 1890 in September of 1996 required the establishment of an ISO to coordinate the safe and reliable delivery of power and to provide open access to the providers and consumers of electric energy. The CAISO began commercial operation on March 31, 1998.

CAISO, like most ISO/RTOs, performs a wide range of functions such as scheduling and dispatching wholesale generation, determining the locational marginal prices for energy, administering the energy and ancillary markets, scheduling transmission within the regional grid, coordinating the planning process for new transmission investment, monitoring the markets for non-competitive tendencies, and implementing mitigation measures.[40] This report, however, focuses on CAISO's regional transmission planning function alone.

### *CAISO Highlights*

- On December 18, 2014, FERC fully accepted the CAISO's third round of tariff revisions, making CAISO the first region in any interconnection to fully comply with the regional requirements of Order No. 1000.
- The CAISO made only minor revisions to its regional transmission planning process to comply with Order 1000 due in large part to the fact it had completed an extensive revision of its planning process in 2010.
- CAISO is the only Region with a competitive solicitation process for projects approved in its regional transmission plan.

## 3.1 Planning Footprint

CAISO manages the flow of electricity across nearly 80% of the wholesale power lines that comprise the power grid in California and parts of Nevada.[41] CAISO is the largest of the 38 balancing authorities (BAs) in the Western Interconnection, with nearly 35% of the total electric load. In addition to facilitating a competitive wholesale power market and serving as the transmission grid operator for the balancing authority footprint, CAISO is responsible for identifying and planning the development of additions and upgrades to the transmission infrastructure that makes up the CAISO BA footprint. The CAISO BA footprint, and hence planning footprint, is reflected in Figure 13.

[40] Monitoring Analytics, "PJM State of the Markets Report- 2010", March 10, 2011.
(Note: The functions listed were originally described in the context of PJM but are equally applicable to other ISO/RTOs as well.)
[41] http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/The-ISO-grid.aspx

**Figure 13: CAISO Balancing Authority Footprint**[42]


Some of the non-CAISO BAs in the state include: PacifiCorp, Los Angeles Department of Water and Power (LADWP), Sierra Pacific Power (SPP), Imperial Irrigation District (IID) and Balancing Authority of Northern California (BANC). CAISO manages the grid operations of the transmission owners listed in Table 6, including three investor-owned utilities: Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric Company (SDG&E). Collectively, CAISO delivers nearly 260 million megawatts-hours of electricity a year using 26,000 circuit miles of transmission to around 30 million customers in its service area.

**Table 7: CAISO Participating Transmission Owners (as of 7/22/14)**

| |
|---|
| Citizen Sunrise Transmission LLC |
| City of Anaheim |
| City of Azusa |
| City of Banning |
| City of Colton |
| City of Pasadena |
| City of Riverside |
| City of Vernon |
| DATC Path 15, LLC |
| Pacific Gas and Electric Company |
| San Diego Gas and Electric Company |
| Southern California Edison Company |
| Startrans IO, LLC |
| Trans Bay Cable LLC |
| Valley Electric Association, Inc. |
| Western Area Power Administration, Sierra Nevada Region |

[42] ibid.

## 3.2 Governance and Funding

CAISO is a nonprofit public benefit corporation governed by a five member Board of Governors.[43] The Board members are elected to three-year staggered terms and are appointed by the Governor of California subject to confirmation by the state senate. The Chair is elected by the majority of the Board. Any prospective Board member is vetted and approved by a Board Nominee Review Committee comprised of representatives from the transmission owners, transmission-dependent utilities, public interest groups, end-users/retail energy providers, alternative energy providers, generators and marketers.

CAISO employs a staff to carry out its roles, responsibilities, and initiatives, which include performing the transmission planning functions for its BA and drafting an annual transmission plan. The CAISO transmission plan is approved by the Board of Governors.

Annually, CAISO sets revenue requirements consisting of operations and maintenance budgets, outstanding debt bond service, capital expenses, and miscellaneous revenue and expenses. The revenue requirement is collected from CAISO customers through the Grid Management Charge (GMC). For the year 2014, the total revenue requirements for CAISO stood at $198 million.[44] The transmission volume for the same year was 247.3 TWh. This resulted in a bundled GMC of $0.801 per MWh for the year 2014. For the year 2015, the total revenue requirement is $198.5 million. CAISO estimates that transmission volume will increase slightly to 248.5TWh, resulting in an estimated bundled GMC of approximately $0.799 per MWh of electricity transmitted. The budget for transmission planning activities is contained within the Develop Infrastructure end-to-end process for which costs/budgets are allocated. Generation interconnection planning is also a component of this process. For 2015, the budget for the Develop Infrastructure process amounts to $10.9 million (5.5% of the total revenue requirement) and 44 staff members.

## 3.3 Regional Transmission Planning

When CAISO began commercial operation in 1998, it relied almost exclusively on its Participating Transmission Owners (PTOs) to develop transmission expansion plans, and then performed a very high level assessment of the integrated PTO expansion plans to ensure the reliable and economic operation of the transmission system. CAISO discontinued this approach in 2006 when it took initial steps toward its goal of creating an annual CAISO Consolidated Transmission Plan.[45] The first transmission plan for the CAISO controlled grid was completed in January of 2007, and it provided a single source of information relating all planning activities undertaken by the CAISO, PTOs, and stakeholders.

[43] CAISO, “ISO/RTO Governance Structure”.
[44] CAISO, “2015 Budget and Grid Management Charge Rates”, December 10, 2014.
[45] CAISO, Memorandum Re: 2005 ISO Transmission Plan, March 2, 2006.

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

The State of California's adoption of new environmental policies and goals[46] created the need for additional changes to the CAISO planning process which were incorporated into tariff revisions that became effective in December of 2010. Changes to the planning process as a result of these tariff revisions included the introduction of a policy-driven criterion for new transmission and a conceptual statewide transmission plan to better inform transmission planning decisions.[47] In addition, the CAISO introduced a competitive solicitation process to determine the most qualified project sponsor, considering both independent transmission developers and PTOs, to construct, own, finance, operate, and maintain certain regional transmission facilities. CAISO termed this new planning process the "revised transmission planning process" or RTPP, and published the first conceptual statewide plan in February of 2011 to be used to inform the 2010/2011 transmission planning cycle.

Most recently, CAISO completed a series of additional revisions to its transmission planning process to comply with the regional planning requirements set forth by Order 1000. Changes to CAISO's transmission planning process to comply with Order 1000 went into effect on October 1, 2013.

## 3.4 CAISO Order 1000 Regional Transmission Planning

CAISO submitted[48] its first FERC Order 1000 regional compliance filing on October 11, 2012.[49] While CAISO believed its existing tariff to be largely compliant with Order 1000 due in large part to the recent changes that had been made to the planning process as part of the RTPP effort, a number of additional planning process changes were incorporated in the revised tariff submitted to FERC including:

- Elimination of federal "right of first refusal" for qualified transmission owners (incumbent owners or projects involving incumbent's own rights-of-way) to build and own new transmission facilities with costs allocated regionally;
- Introduction of tariff provisions that provide qualified transmission owners the "right of first refusal" for local projects;
- Greater opportunities for stakeholders to propose public policy requirements in the transmission planning process;
- Introduction of tariff enhancements to add clarity and transparency to the ISO's competitive solicitation process;
- Amendments in tariff language for fair consideration of non-transmission solutions; and

[46] These policies and goals included the adoption on May 4, 2010 of a statewide policy on the use of coastal and estuarine water for power plant cooling by the State Water Resources Control Board, and the state's move toward a renewable portfolio standard of 33% by 2020.
[47] CAISO, "2012-2013 Transmission Plan", March 20, 2013.
[48] Because CAISO serves as the transmission provider for its participating transmission owners, the responsibility for posting and filing tariff provisions resides with CAISO and not the individual participating transmission owners.
[49] http://www.ferc.gov/industries/electric/indus-act/trans-plan/filings.asp

- Amendments in tariff provisions for proactive project monitoring of approved projects.

On April 18, 2013, FERC issued an order accepting CAISO's first regional compliance filing, including an October 1, 2013 effective date, subject to certain modifications.[50] Some of the key modifications required by FERC in its initial compliance order involved:

- Clarifications on the qualification criteria for determining transmission developers eligible to submit proposals/bids in the competitive solicitation process;
- Clarifications on the information that a potential developer must submit in support of a transmission project it proposes in the regional transmission planning process; and
- Clarifications on the evaluation process for selecting transmission proposals in the regional transmission plan for purposes of cost allocation.

On August 20, 2013, CAISO filed its second round of revisions to its tariff to comply with the first compliance order. On March 20, 2014, FERC issued an order accepting, subject to modifications, the second compliance filing of CAISO.[51] FERC determined that CAISO had complied with most of the directives from the first compliance order, but had failed to clarify how a decision not to consider a previously identified transmission need driven by public policy requirements would be provided to stakeholders, and required further clarifications with regard to certain aspects of the criteria that would be used to identify developers eligible to submit a proposal into the competitive solicitation process.

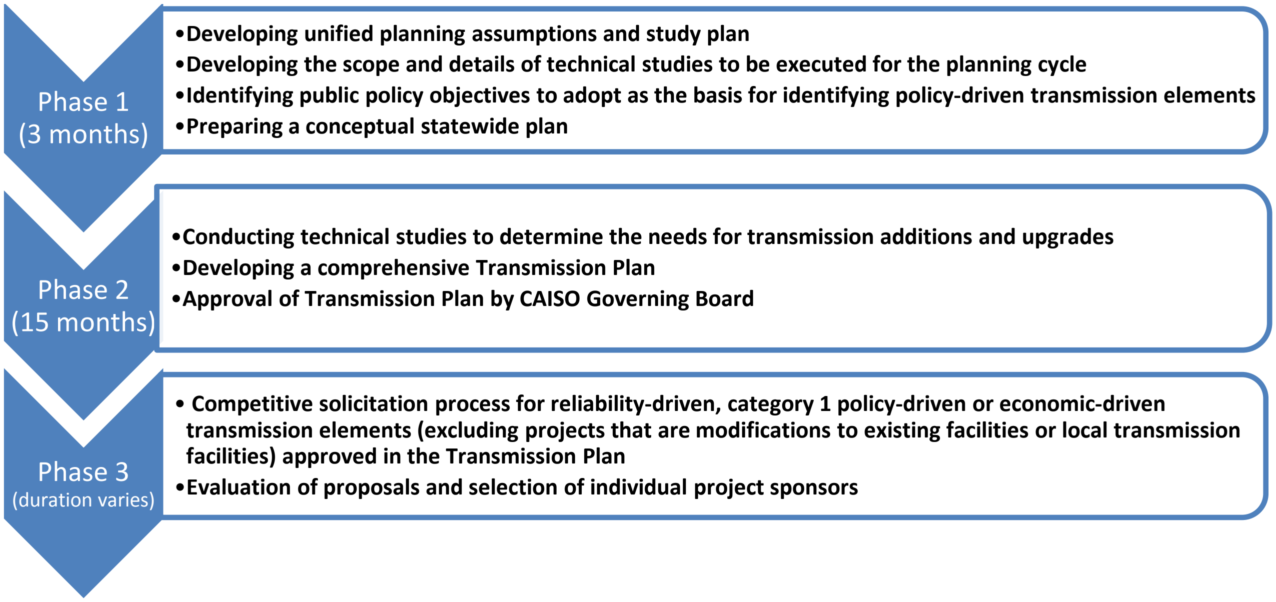
The CAISO filed its third round of tariff revisions to comply with the regional planning requirements set forth by Order 1000 on May 19, 2014. On December 18, 2014, FERC fully accepted the CAISO's third round of tariff revisions, making CAISO the first region in all interconnections to fully comply with the regional requirements of Order No. 1000.

### 3.4.1 Planning Process Overview

CAISO's comprehensive Transmission Planning Process (TPP) is initiated on an annual basis and consists of three consecutive phases spread over a roughly 23 month period. The TPP commences each January, and results in the Board-approval of necessary projects 15 months later. Major deliverables of the TPP are the conceptual statewide plan and unified planning assumptions and study plan (for Phase 1); technical studies and comprehensive transmission plan (for Phase 2); and, if applicable, selection of proposals to build and own new transmission facilities identified in the Board-approved plan (for Phase 3). The three planning phases are summarized in Figure 14.

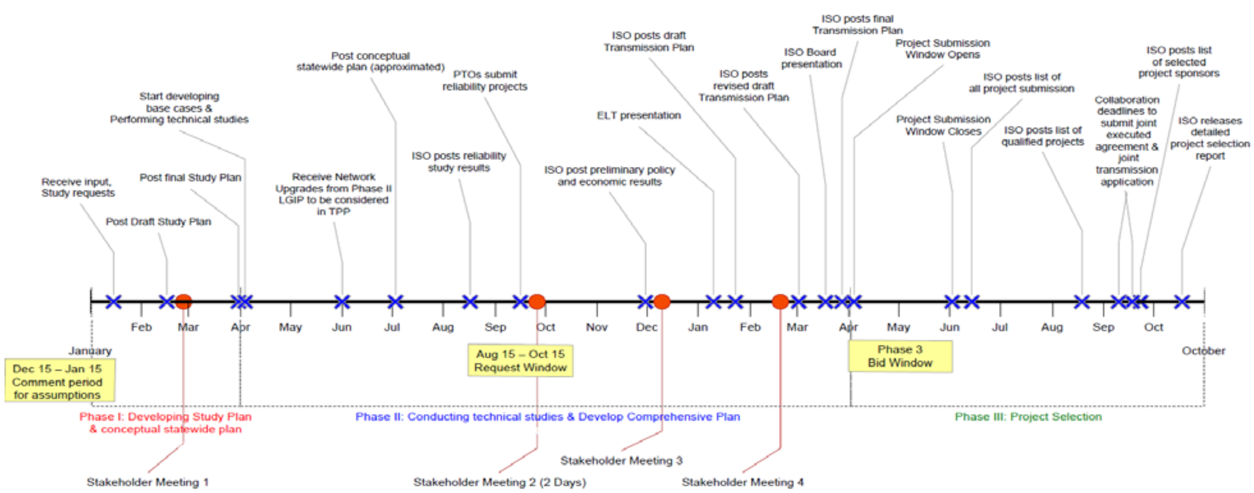
[50] FERC, "California Independent System Operator- Order on Clarification and Compliance", 146 FERC ¶ 61,198.
[51] FERC, "California Independent System Operator- Order on Rehearing and Compliance", 149 FERC ¶ 61,249.

**Figure 14: Major Activities of the CAISO Transmission Planning Process**[52]




Phases 1 and 2 of the transmission planning process are conducted over a 15-month period. As such, the last three months of phase 2 of one planning cycle will overlap with phase 1 of the next cycle, which also spans three months. The CAISO will conduct Phase 3 of the TPP, the competitive solicitation for sponsors to build and own eligible transmission facilities identified in the final plan, following Board approval of the comprehensive plan and in parallel with the start of phase 2 of the next annual cycle. The general timeline of the TPP is graphically represented in Figure 13.

**Figure 15: General Timeline of CAISO Transmission Planning Process**




***Source***: *CAISO BPM*

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

Major aspects of Phase 1 and Phase 2 of the TPP are described in additional detail in subsequent sections. For additional detail regarding the competitive solicitation process (Phase 3), refer to the CAISO BPM for the Transmission Planning Process.

### 3.4.2 Sources of Planning Data and Assumptions

The first phase of the TPP entails the development of the unified planning assumptions to be used in the development of the various public policy and technical studies performed as part of Phase 2. The unified planning assumptions are compiled from information received from PTOs, neighboring BAs, neighboring regional and sub-regional planning groups, and state agencies who respond to the data request issued by CAISO each December. During the development of the unified planning assumptions, stakeholders are also provided the opportunity to submit specific comments to CAISO regarding demand response programs requested to be included in the base cases, as well as generation and non-transmission alternatives proposed for consideration in the planning process.

Specific assumptions with regard to demand forecasts and renewable resource procurement plans are provided to CAISO for inclusion in the TPP by the California Energy Commission (CEC) and the CPUC. In addition, CAISO uses WECC-PCC power flow base cases and the TEPPC Common Case dataset as the starting point for the development of its study models.

Additional detail with regard to the data and assumptions, including the source of the information used for the various technical studies performed by the CAISO, are outlined in the subsequent sections.

#### *Conceptual Statewide Transmission Plan*

CAISO initiates the development of a conceptual statewide transmission plan during Phase 1 of the TPP, and typically completes that plan during Phase 2 such that it can become an input into the study process to identify the need for public policy-driven transmission elements. Development of this plan was incorporated into the TPP in 2010 based on the recognition that the need for new transmission infrastructure as a result of public policy requirements could apply to the entire state, including areas outside of the CAISO controlled grid. The plan is "conceptual" in nature to the extent that it is not binding on transmission providers outside of the CAISO footprint. However, it provides a statewide perspective on how to develop needed new transmission to most efficiently meet the statewide 33% RPS mandate. CAISO prepares the conceptual statewide transmission plan in coordination with the California Transmission Planning Group (CTPG) and neighboring balancing authorities, to the extent possible.[53]

### 3.4.3 Transmission Plan Analysis

During Phase 2 of the TPP, CAISO conducts a series of sequential technical studies and analyses to identify transmission upgrades or additions, or non-transmission alternatives, needed to reliably operate

[53] The CTPG has been largely inactive in recent years as its participants have been focused on complying with Order 1000. As such, the 2014-2015 conceptual statewide transmission plan was developed by updating the previous plan using current CAISO information and publicly available information from neighboring planning entities. CAISO plans to revisit this approach as the FERC Order 1000 interregional coordination efforts gain momentum.

the CAISO controlled grid, meet the state's public policy requirements, and provide additional benefits to ratepayers. The technical studies performed to identify the reliability, public policy, and economic-driven transmission elements of the comprehensive Transmission Plan are described below.

### *Reliability Assessments*

CAISO performs a series of reliability assessments to identify the need for transmission upgrades and additions to ensure that the CAISO controlled grid will meet or exceed all applicable NERC Standards and WECC/ISO reliability criteria in both the near-term (5-year) and longer-term (10-year) study horizons. The term "reliability assessments" encompasses several technical studies conducted by CAISO such as power flow, transient stability, and voltage stability studies. These assessments are performed on the bulk system as well as the local areas under the CAISO controlled grid.[54]

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

Power flow base cases from WECC are used as the starting point of the CAISO TPP base cases. These cases are used to represent the transmission system outside CAISO's controlled grid for the relevant study year. The portion of the CAISO controlled grid that is to be studied in each case developed for the various reliability assessments is updated with the latest model information as provided by the PTOs, and further adjusted, as needed, to align with the specific conditions (load, generation, path flows) for the study as outlined in the Study Plan.

If during the course of conducting the reliability assessments system performance criteria are not met, CAISO will develop mitigation plans to address the performance issues and will consider alternative mitigation proposals submitted by PTOs and other stakeholders during the CAISO Request Window and in accordance with the CAISO's submission requirements. More information regarding the Request Window is provided below.

In addition to the reliability assessments described above, CAISO performs additional technical studies related to long-term Congestion Revenue Rights (LT-CRRs) and local capacity requirements. Proposals to meet any needs identified by CAISO as part of these studies can also be submitted during the Request Window. Finally, CAISO will evaluate Generator Interconnection Process (GIP) network upgrades that might be eligible for modification or addition in the comprehensive Transmission Plan, as well as any Location Constrained Resource Interconnection Facilities (LCRIF) or merchant projects submitted through the Request Window before proceeding with the evaluation of policy-driven needs. Additional details regarding these studies and categories of projects can be found in the BPM for the Transmission Planning Process.

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

### Generation Modeling Assumptions

New generators modeled in CAISO's reliability studies are classified as follows:[55]

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

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

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

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

### Transmission Modeling Assumptions

Transmission infrastructure reflected in the technical models consists of existing transmission projects and future transmission projects that have received CAISO Board-approval in previous planning cycles. Transmission upgrades needed to interconnect new modeled generation is also included.

### Demand Forecast

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

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

### Other Modeling Assumptions

Data and assumptions related to demand response programs and energy storage are also reflected in the technical models to the extent that such information is submitted to CAISO for consideration in the planning studies by stakeholders during phase 1 of the TPP.

## *Policy-Driven Need Assessment*

Once CAISO has identified reliability-driven transmission solutions, Location Constrained Resource Interconnection Facilities (LCRIF) projects, projects to maintain long-term Congestion Revenue Rights (LT-CRRs), qualified Merchant Transmission Facility projects, and needed GIP Network Upgrades, it turns to evaluating the need for policy-driven transmission elements. This effort truly begins in Phase 1 of the TPP, however, with identifying the public policy objectives CAISO proposes to adopt for transmission planning purposes in the current planning cycle.

The focus of CAISO's policy-driven needs assessment for the past number of years has been on identifying new transmission projects needed to achieve California's Renewable Portfolio Standard that calls for eligible renewable resources to provide 33 percent of the state's electric retail sales in 2020 and beyond. To perform this assessment, CAISO first establishes the renewable resource portfolios that are to be considered in the studies. These portfolios are provided by the CPUC and CEC and are an output of the Long Term Procurement Plan proceedings.[56] The CPUC is the agency that oversees the supply procurement activities of the investor-owned utilities and retail direct access providers, and manages the LTPP proceedings.[57] Stakeholders have an opportunity to review and comment on the proposed resource portfolios before they are finalized as an input into the TPP.

There has been a significant amount of uncertainty regarding where generation capacity needed to achieve California's 33% RPS will locate. In the context of identifying new transmission infrastructure needed to support these resources, CAISO has managed this uncertainty by applying a "least regrets" principle to the evaluation of policy-driven transmission needs. This principle involves developing several alternative resource development portfolios or scenarios, and then identifying the needed transmission to support each portfolio followed by selecting for approval those transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios.

Because the base renewable resource portfolio is included in the models used for the reliability assessments, the results of the reliability assessments are considered to be part of the policy-driven need assessment. Still, those study results are supplemented with additional studies that contribute to identifying the "least regrets" policy-driven transmission needs considering both the base case and alternative renewable resource portfolios. Additional studies performed to identify the "least regrets" policy-driven transmission needs include production cost modeling simulations to identify stressed system conditions for evaluation using power flow and stability tools to ensure all system performance requirements continue to be met; and a deliverability assessment to verify the deliverability (within

[56] http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/

[57] Separate from, but in coordination with the TPP, the CAISO performs renewable integrations studies to serve as input into the CPUC LTPP process.

CAISO or import into CAISO) of the resources modeled in the renewable resource portfolios such that the RPS targets will indeed be met.

### *Economic Planning Studies*

Once CAISO has identified policy-driven transmission solutions in addition to the previously identified reliability-driven solutions, these results will be taken as inputs and modeled in economic planning studies. This approach ensures that the economic-driven transmission needs are not redundant and are above and beyond reliability- and policy-driven transmission needs.

The purpose of the economic studies is to identify potential congestion within the CAISO-controlled grid and potential additional network upgrades that will provide economic benefit for CAISO ratepayers based on the Transmission Economic Assessment Methodology (TEAM). [58] The studies are performed using the ABB GridView™ production cost simulation tool. CAISO uses the WECC-TEPPC 10-year database as the starting point for its 5- and 10-year economic databases, updating the TEPPC modeling assumptions for the CAISO BA to be consistent with the unified planning assumptions used for the reliability and policy-driven needs assessments. TEPPC data and assumptions for the other Western Interconnection BAs are left intact, unless otherwise noted in the comprehensive transmission plan report.

In the first step of the economic studies, a production cost simulation is run for each hour of the study year. Congestion is identified and ranked in severity of congestion costs and congestion duration in hours. The results from these initial production cost simulations are reviewed in conjunction with requests for economic studies received during Phase 1 of the TPP to determine high priority economic studies (congested lines or paths) for evaluation. CAISO will perform up to five high priority economic planning studies, but may perform more should stakeholder study requests or congestion observed in the production cost simulations so warrant.

In the second study step, plans to mitigate identified congestion are evaluated for each high priority economic study. Economic benefits of each network upgrade alternative are quantified, and a cost-benefit analysis is performed to select the alternative with the greatest net benefit. The types of benefits quantified include production benefits (consumer energy cost decreases, increased load serving entity owned generation revenues, and increased transmission congestion revenues), capacity benefits (system resource adequacy — RA —savings and local RA savings), and other quantifiable benefits (reduction in transmission line losses).

Production benefits are quantified by comparing the production cost simulation results before the addition of a network upgrade with the results obtained after the network upgrade has been added to the system. The system RA capacity benefits corresponds to a situation where a network upgrade for a facility that imports energy into the CAISO system leads to a reduction of CAISO system resource requirements, as long as the out-of-state resource that is imported via the network upgrade is less expensive to procure than the in-state resource that would have otherwise been required. The local RA

[58] CAISO, ”Transmission Economic Assessment Methodology (TEAM)”, June 2004.

capacity savings correspond to a situation where the network upgrade leads to a reduction of local capacity requirements in a load area.[59]

### 3.4.4 Request Window

CAISO will open a request window during Phase 2 of the TPP following the posting of the technical reliability study results for the submission of proposed transmission or non-transmission solutions to meet the identified reliability-driven needs. LCRIF projects, proposals for merchant transmission projects, proposed transmission solutions to maintain the feasibility of LT-CRRs, and efficient or cost-effective regional transmission alternatives for meeting identified needs will also be accepted during the request window.

PTOs, the CEC, the CPUC, and any other interested party can submit proposed solutions, but they must do so using the submission form that is available on the CAISO website.[60] For a project proposal to be considered in the TPP, it must fall under one of the categories of projects listed, must be located within or interconnected to the CAISO controlled grid, all requested data or information must be complete, and it cannot be duplicative of transmission upgrades or additions previously approved by CAISO.

### 3.4.5 Selecting Transmission Solutions for Inclusion in the Transmission Plan

Once CAISO has identified a reliability-driven need, the preferred alternative to mitigate the need is determined by performing a comparable assessment of competing alternatives and considering whether the alternatives are technically sound. The selected alternative is typically the most cost-effective solution, however, in some cases the most cost effective solution may not be selected or recommended if CAISO finds that another approach appears to be a more prudent overall solution for the system.[61]

Policy-driven transmission solutions are identified using the least-regrets approach described above, and with consideration of a number of additional factors including: the cost of the alternatives, environmental impact, potential future connection to other resources enabled by the alternatives, the potential for the alternative to provide access to resources needed for integration, and the effect of uncertainty associated with any of the evaluation criteria.[62]

The identification of economic-driven transmission solutions is based on the evaluation of potential transmission projects and upgrades through the TEAM process. This process outlines five key requirements for evaluating any potential transmission projects:

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[59] As part of the TPP the CAISO performs special reliability studies to determine the Reliability Requirements for Resource Adequacy. An assessment of minimum local capacity requirements (LCR) is conducted for the upcoming year and for a 5- and 10-year planning horizon, and a Resource Adequacy Import Allocation study is conducted to determine the maximum resource adequacy import capability into the CAISO system. The 10-year LCR studies provide input into the CPUC LTPP process to provide indication of any potential capacity deficiencies that need to trigger a new LTPP proceeding.

[60] http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx

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

[62] ibid.

- A comprehensive benefits-cost framework that summarizes the potential benefits, costs and risk of transmission projects
- Accurate modeling of physical transmission flows to accurately forecast the reliability impacts of a potential transmission upgrade
- Incorporating the strategic behavior of market participants in a production cost modeling framework (either through a game-theoretic approach or using historic relationships between market variables and market power metrics)[63]
- Incorporating the impact of risk and uncertainty on the transmission expansion framework[64]
- Considering resource alternatives to transmission expansion (demand-side management, renewables addition, alternative transmission upgrades, etc.)

Once the CAISO Board approves the comprehensive Transmission Plan, the approval of the reliability, policy, and economic-driven transmission solutions outlined within the plan authorizes the implementation of those projects and enables cost recovery through CAISO transmission rates. It is at this point that CAISO will initiate the competitive solicitation process and accept proposals from project sponsors to build and own the eligible transmission facilities. Projects eligible for competitive solicitation are reliability-driven, category 1[65] policy-driven, or economic-driven elements, excluding projects that are modifications to existing facilities or local transmission facilities.

### *Consideration of Non-Transmission Alternatives*

The CAISO Board cannot "approve" non-transmission alternatives to identified reliability, policy, or economic-driven needs, but CAISO is making an effort to place greater emphasis on the consideration of non-transmission alternatives as preferred solutions over transmission projects in the TPP.[66] Non-transmission alternatives considered as part of the TPP include conventional generation, as well as "preferred resources" as defined by the CPUC, and include demand response and energy efficiency. Renewable generation and energy storage is also considered.

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[63] CAISO recognized that in a restructured market environment suppliers are likely to optimize their bidding strategies in response to changing system condition or observed changes in the behavior of other market participants. As such, they determined that evaluating economic benefits assuming marginal cost pricing as calculated by a production cost model may result in inaccurate benefit estimates, and developed a methodology for modeling strategic bidding within the production cost model.

[64] Risk and uncertainty associated with future market conditions is addressed by selecting a representative set of market scenarios to measure benefits of transmission expansion candidates. Weighting factors are then assigned to the different scenarios such that the expected benefit and range of benefits for a candidate can be determined. Variables that may be altered in the market scenarios could include future demand levels, gas prices, strategic bidding behavior, or hydro availability.

[65] Category 1 policy-driven transmission elements are those determined to be needed in the baseline scenario and at least a significant percentage of the additional policy scenarios evaluated, and are therefore recommended for approval as part of the comprehensive Transmission Plan.

[66] The CAISO issued a paper on September 4, 2013, as part of the 2013-2014 transmission planning cycle in which it presented a methodology to support California's policy emphasis on the use of preferred resources. This paper can be accessed here: http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf

### 3.4.6 Draft 2015-2016 Study Plan

CAISO released its draft Study Plan for the 2015-2016 Transmission Planning Process on February 17, 2015 and held a public stakeholder meeting to discuss the draft study plan on February 23, 2015.

Study years for CAISO's reliability assessments will be 2017 and 2020 for the near-term studies, and 2025 for the longer-term studies. A combination of peak, off-peak, and light load seasonal base cases will be created for the assessment of reliability-driven transmission needs of the CAISO-controlled grid. In addition to the base cases, several sensitivity cases will be studied for many of the local areas. These cases will be used to assess impacts of specific assumptions on the reliability of the transmission system under high CEC forecasted load, heavy renewable output, generation retirement scenarios, and low hydro conditions.

The overarching policy objective to be addressed in the 2015-2016 planning cycle continues to be the state's mandate for 33% renewables by 2020. For the 2015-2016 planning cycle, the CPUC and CEC have submitted two renewable resource portfolios to CAISO for consideration in the TPP, including: the "33% 2025 Mid AAEE" (Mid Additional Achievable Energy Efficiency) portfolio and the "High DG 33% 2025 Mid AAEE + DSM" portfolio.[67] Both portfolios were originally developed for the 2014-2015 TPP, but include an update made to location information assumed for distributed generation resources in the SDG&E service territory.[68] The "33% 2025 Mid AAEE" portfolio is intended to be the base case portfolio. These portfolios will be used to identify policy-driven needs.

Production cost simulation and congestion analysis will be performed in the 2015-2016 planning cycle for the years 2020 and 2025. The latest available TEPPC database will be used as the starting database for the economic studies. Data and assumptions related to California will be updated to reflect the unified planning assumptions, with the exception of using a 1-in-2 Mid Additional Achievable Energy Efficiency (AAEE) demand forecast as compared to the 1-in-5 Mid AAEE forecast that will be used for the system-wide reliability assessments. The data and assumptions for other areas of the interconnection will be left as-is. The window to submit economic study requests closed on March 9, 2015. CAISO will select high priority economic studies based on the results of the congestion analysis performed in Phase 2 of the 2015-2016 planning cycle and the economic study requests received.

CAISO plans to perform a special study as part of the 2015-2016 planning cycle to explore, from an informational standpoint only, the potential transmission implications of increased grid-connected renewable generation needed to meet a 50 percent renewable energy goal in 2030. This renewable energy goal was announced by California Governor Jerry Brown on January 5, 2015, but is not yet a formal state-approved policy requirement. As such, CAISO will not use it as a basis for approving any policy-driven transmission as part of the TPP. CAISO will coordinate with the CPUC on obtaining renewable resource portfolios for the 50 percent renewable energy goal to be used in this special study.

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[67] CPUC , "Base Case Renewable Resource Portfolio and an Alternative Renewable Resource Portfolio for the CAISO 2015-2016 Transmission Planning Process", March 11, 2015.

[68] It was determined that the CPUC's new RPS Calculator (version 6) was not yet ready to inform the 2015-2016 TPP, and so the portfolios studied for the 2014-2015 TPP, with the update described, were suggested to be reused.

The final 2015-2016 Study Plan will be published March 31, 2015.

### 3.4.7 Draft 2014-2015 Transmission Plan

CAISO released its draft 2014-2015 Transmission Plan on February 2, 2015 and held a public stakeholder meeting to discuss the draft comprehensive Transmission Plan on February 17, 2015.

Key findings presented in the draft Transmission Plan include the identification of 7 transmission projects as being needed to maintain transmission system reliability.[69] This number of reliability-driven transmission projects is significantly less than the number identified in previous planning cycles and is intended to reflect the progress made in addressing longer term reliability needs as well as the increased reliance on the consideration of preferred resources.

No new major transmission projects were identified to support the achievement of California's 33% RPS requirement given the transmission projects already approved or progressing through the CPUC approval process. One economic-driven transmission project is being recommended for approval, but neither this project nor the reliability-driven projects included in the draft plan are eligible for competitive solicitation.

Recommendations made for future planning cycles focus on the need to continue refining methods to ensure that preferred resources are provided the maximum opportunity to meet transmission system needs.

## 3.5 Planning Coordination

CAISO's TPP involves significant collaboration with the CPUC, CEC, and many other stakeholders, including neighboring transmission providers and other regional planning organizations. Most notably, many of the planning data and assumptions incorporated into the technical studies performed in support of the TPP are developed by the CPUC and CEC.[70] In addition, CAISO provides significant input back to these agencies to use as input into their planning functions. Still, the CAISO, CPUC, and CEC have undertaken efforts to further improve planning coordination. In particular, these agencies have worked to align three core processes including the:[71]

- Long-term forecast of energy demand produced by the CEC as part of its biennial Integrated Energy Policy Report (IEPR),
- Biennial Long Term Procurement Plan proceeding (LTPP) conducted by the CPUC, and the
- Annual Transmission Planning Process (TPP) performed by the ISO.

[69] Under existing tariff provisions, CAISO management can approve transmission projects with capital costs equal to or less than $50 million. Such projects do not require further Board approval. Of the 7 projects identified, only two have an estimated cost greater than $50 million, thereby requiring Board approval. The other 5 projects have already received management approval.

[70] The CPUC and CAISO signed a Memorandum of Understanding on May 13, 2010 that served as a formal commitment to closer coordination of transmission and resource planning information between the two organizations.

[71] CAISO, "2014-2015 Transmission Plan - Draft", February 2, 2015.

In addition to aligning these three processes, the agencies have also agreed on an annual process to be performed in the fall of each year to develop assumptions and scenarios to be used in infrastructure planning activities in the coming year.

CAISO is currently engaged with the other three Western Planning Regions to define the Interregional (IR) Coordination process approved by FERC on December 18, 2015. More details regarding these IR Coordination activities are provided later in this report. Current efforts by CAISO with regard to engaging with other regional planning processes are documented in the BPM for the Transmission Planning Process. These efforts are largely informal with the exception of CAISO's solicitation of neighboring regional planning groups for their participation in the development of the unified planning assumptions and study plan. CAISO's introduction of the conceptual statewide transmission plan in 2010 was an additional effort to more formally coordinate transmission planning across the CAISO BA boundaries and incorporate planned facilities of interconnected BAs into the TPP. The goal of all of CAISO's collaboration efforts is to ensure the meaningful exchange of planning information and that transmission expansion plans of CAISO and interconnected transmission providers are simultaneously feasible and avoid the duplication of facilities.

Finally, as is the case with the other western Planning Regions, CAISO participates actively at WECC through various WECC committees including the Planning Coordination Committee, Operations Committee, and TEPPC. CAISO not only supplies data for use in the construction of the WECC databases, but also uses these databases as the starting point for its technical studies. Further, CAISO participates in technical studies performed at WECC that may have a regional impact on the CAISO-controlled grid.

## 3.6 Stakeholder Process

CAISO solicits stakeholder input in the course of conducting many of its initiatives, including its regional transmission planning process. The CAISO BPM for the Transmission Planning Process outlines discrete opportunities for stakeholder input throughout the planning cycle. In addition to holding at least four public stakeholder meetings each planning cycle, stakeholders are invited to provide input and submit comments or recommendations with regard to many of the activities conducted and deliverables produced as part of the planning process.

The four stakeholder meetings held during the planning cycle are scheduled around major activities of the planning process. This allows CAISO to present and acquire stakeholder input on key aspects of the process including the draft study plan, technical study results, and the content of the conceptual statewide transmission plan and draft comprehensive Transmission Plan. The schedule for all major activities to be conducted as part of the planning cycle, including the dates of the four stakeholder meetings, posting dates of major process deliverables, and notice of stakeholder comment periods are outlined in the final study plan produced for each planning cycle.

In the course of developing the unified planning assumptions and study plan, CAISO solicits stakeholder feedback specifically with regard to demand response and generation or other non-transmission alternative assumptions to be considered in the planning process. In order for CAISO to be able to use stakeholder input with regard to these assumptions, minimum requirements for data/information are outlined in the BPM.

All stakeholder meetings are noticed by CAISO through a Market Notice and are posted to CAISO's calendar, located on the CAISO website (www.CAISO.com).

## 3.7 Links to Key Documents

Draft 2015-2016 Unified Planning Assumptions and Study Plan

Draft 2014-2015 Transmission Plan

CAISO Tariff – Section 24: Comprehensive Transmission Planning Process as of May 19, 2014

BPM for the Transmission Planning Process

# Chapter 4: ColumbiaGrid

ColumbiaGrid is a non-profit membership corporation formed in 2006 to improve the operational efficiency, reliability, and planned expansion of the Pacific Northwest transmission grid.[72] ColumbiaGrid carries out activities in support of this mission as defined and funded through a series of Functional Agreements concluded among the corporation, its members and qualified non-member participants.[73] The ColumbiaGrid Planning and Expansion Functional Agreement (PEFA) supports and facilitates coordinated, multi-system transmission expansion planning through an open and transparent process. In addition to the PEFA, and for compliance with Order 1000, ColumbiaGrid has developed the First Amended and Restated Order 1000 Functional Agreement to work in tandem with the PEFA to carry out a single, coordinated transmission planning process.

In addition to transmission planning related activities, functional agreements for a common OASIS portal[74] and variable transfer limit study effort[75] are currently in place. More information regarding these efforts can be accessed from the ColumbiaGrid website (www.ColumbiaGrid.org).

### *ColumbiaGrid Highlights*

- ColumbiaGrid's public utility Transmission Providers are awaiting an Order from FERC on their third round of compliance filings addressing the regional planning requirements of Order 1000.
- The 2015 regional planning cycle is underway and is being conducted under Order 1000 compliance.
- ColumbiaGrid has elected to maintain a production cost model dataset built from the TEPPC 2010 backcast dataset, as opposed to TEPPC's 10-year dataset, to be used in its future economic planning studies.

## 4.1 Planning Footprint

There are currently eight members of ColumbiaGrid, all of which are party to the PEFA: Avista Corporation, Bonneville Power Administration (BPA), Chelan County Public Utility District (PUD), Grant County PUD, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. In addition, three qualified non-member participants are also a party to the PEFA: Cowlitz PUD, Douglas County PUD and Enbridge. Parties to the Order 1000 Functional Agreement currently include

[72] ColumbiaGrid, "What is ColumbiaGrid," https://www.columbiagrid.org/what-is-columbia-grid.cfm.
[73] Signatories to the ColumbiaGrid functional agreements are referred to as "participants" and include both members and non-members of the corporation. Qualifications for non-member participation are outlined in the individual functional agreements.
[74] The common OASIS portal is a single interface for transmission customers to be able to arrange transmission service across multiple paths using participating transmission providers' systems and to enable participating transmission providers to post transmission information. The OASIS Portal was launched in mid-2011, but is no longer active. However, ColumbiaGrid continues to explore, analyze, and develop new ways to improve markets and to improve transmission planning, expansion, optimization, and utilization.
[75] The purpose of the Variable Transfer Limits study effort is to determine the Variable Transfer Limits of the Northwest AC Intertie, Bonneville Power Administration's network system, and possibly the other Bonneville interties.

ColumbiaGrid's three public utility Transmission Providers: Avista Corporation, Puget Sound Energy, and MATL LLP.[76] Collectively, ColumbiaGrid's members and planning participants (planning parties) manage more than 22,000 circuit-miles of transmission.

**Figure 16: ColumbiaGrid Planning Footprint**


***Source**: ColumbiaGrid*

## 4.2 Governance

ColumbiaGrid is managed by a three-member, independent board of directors and maintains a small, dedicated staff that includes both corporate and program staff (e.g. transmission planning staff).[77] The

[76] Enbridge is the owner of MATL LLP.
[77] Currently, ColumbiaGrid has a staff of ten individuals.

transmission planning activities are carried out by the program staff with input and participation from the planning parties and other stakeholders. The primary mechanism for participating in the planning process is through membership in Study Teams. ColumbiaGrid staff holds public meetings to solicit participation in Study Teams, and to the extent that there are no restrictions with regard to confidential information or Critical Energy Infrastructure Information (CEII), any planning party or interested stakeholder can participate on a Study Team.

### 4.2.1 Parties to the Functional Agreements

The rights and obligations of parties to the PEFA and/or Order 1000 Functional Agreement are set forth in those agreements. No distinction is made between interested entities that may wish to be a party to the PEFA.[78] In contrast, parties to the Order 1000 Functional Agreement can include: Enrolled Parties, Interregional Transmission Project (ITP) Proponents, and Governmental Non-Enrolled Parties. Enrolled Parties are those subject to the requirements of Order 1000, including cost allocations, as implemented in the regional planning process conducted by ColumbiaGrid. Governmental Non-Enrolled Parties is a category established for those non-public utilities wishing to be a party to the Order 1000 Functional Agreement, but not wishing to be enrolled in the Region for the purposes of cost allocation. ITP Proponents are also not enrolled in the ColumbiaGrid Planning Region, but rather must be enrolled in some other western Planning Region.

As of the date of this report only ColumbiaGrid's three public utility Transmission Providers have signed the Order 1000 Functional Agreement as Enrolled Parties. No party has yet executed the Order 1000 Functional Agreement as a Governmental Non-Enrolled Party or ITP Proponent.

Any interested stakeholder is invited to participate in the ColumbiaGrid regional planning process (PEFA and Order 1000), and may propose a solution for an identified Order 1000 need, but Order 1000 cost allocation can only be requested by Enrolled Parties and ITP Proponents.

## 4.3 Funding for Regional Planning Activities

Provisions for funding the regional planning activities by the planning parties are set forth in the PEFA/Order 1000 Functional Agreement. The PEFA establishes a Maximum Total Payment Obligation (MTPO) for each payment cycle (a period of two years corresponding to the planning cycle) of $4.2 million, subject to annual inflation/deflation and corporate overheads adjustments. With the consent of the voting members of ColumbiaGrid, this cap can be modified for different planning years. For the planning year 2015-16, the MPTO stands at $4.98 million (accounting for inflation effects and corporate overheads).[79] Each party to the PEFA is then allocated a share of the PEFA budget in accordance with an allocation percentage calculated by ColumbiaGrid that takes into account the dollar value of net transmission plant of each party as compared to the total dollar value of net transmission plant of all parties, and each party's proportion of the total annual area load of all parties. If the resulting

[78] Any entity that owns or operates or proposes to own or operate transmission facilities in the region is eligible to become a PEFA member.
[79] ColumbiaGrid, "2015/16 Budget-Final Draft," December 10, 2014.

allocations are such that BPA is allocated more than 49.9% of the MTPO, an alternative allocation equation is used. Current allocations of the PEFA budget by planning party are shown in Table 8.

**Table 8: Current Budget Allocations by PEFA Party (as of 5/8/14)**

| Planning Party | PEFA Budget Allocation Percentage |
|---|---|
| **Avista** | 8.56 |
| **BPA** | 49.9 |
| **Chelan** | 3.25 |
| **Cowlitz** | 2.92 |
| **Douglas** | 1.56 |
| **Enbridge** | 1.05 |
| **Grant** | 3.21 |
| **Puget** | 16.50 |
| **Seattle** | 5.41 |
| **Snohomish** | 3.92 |
| **Tacoma** | 3.72 |

Obligations for funding ColumbiaGrid's incremental regional transmission planning activities under Order 1000 are established in the Order 1000 Functional Agreement. Each entity that is a party to the Order 1000 Functional Agreement is obligated to make a base payment to ColumbiaGrid of $50,000 for the planning cycle in which they become a party to the Agreement. A monthly fee is then required for every month following the planning cycle in which the base payment is made until the party has withdrawn from the Agreement.

Any Order 1000 Enrolled Party requesting cost allocation is also required to pay ColumbiaGrid an incremental cost for performing the requested cost allocation. The incremental cost is a function of the per-hour cost of the employees performing the cost allocation and the cost of any additional services ColumbiaGrid must obtain in order to perform the cost allocation.

## 4.4 Regional Transmission Planning

ColumbiaGrid initiated its first regional transmission planning activities in 2007 with the execution of the first PEFA agreement by ColumbiaGrid's current members. The PEFA established a coordinated, "single utility" approach to transmission planning conducted by the ColumbiaGrid staff, PEFA parties, and interested stakeholders. Major deliverables of the planning process included Annual System Assessment Reports and a Biennial Transmission Plan approved by the ColumbiaGrid Board.

Also in 2007, FERC issued Order 890, and ColumbiaGrid facilitated a process for the PEFA parties to develop and draft their Attachment Ks required for compliance with the Order. The planning process outlined in the PEFA met the majority of the regional planning requirements established by Order 890 with the exception of the requirements for economic planning studies and the cost allocation for new projects. As a result, the PEFA was revised such that the requirement for economic studies would be met by the PEFA Transmission Providers working with ColumbiaGrid to submit requests to WECC for economic planning studies. Further, the PEFA was revised to incorporate cost allocation methodologies for projects considered in the planning process affecting more than a single transmission system. As part of its Order 890 process, ColumbiaGrid provided only cost allocation recommendations to facilitate mutual agreement by parties on cost allocation conducted as part of the Study Team process.

## 4.5 ColumbiaGrid Order 1000 Regional Transmission Planning

The ColumbiaGrid public utility Transmission Provider planning parties (Avista, Puget Sound and MATL LLP) submitted their first Order 1000 regional compliance filings to FERC on October 11, 2012. BPA also filed Attachment K modifications at the same time, even though it is a governmental utility and therefore not subject to FERC jurisdiction. BPA voluntarily filed its OATT with FERC first in 1996 to confirm that it substantially conforms or is superior to FERC's pro forma OATT, and has consistently filed tariff revisions since.

In reviewing the PEFA regional planning process for any changes necessary to conform to Order 1000, ColumbiaGrid planning parties determined that the existing planning process already largely complied with Order 1000. To fully address the requirements of Order 1000, however, they established provisions within the PEFA for the identification and selection of Order 1000 regional projects, developed detailed formulas and instructions for performing cost allocation on those Order 1000 projects, and modified/added language to include references to the consideration of needs driven by public policy requirements.

On June 20, 2013, FERC published its unified response to the ColumbiaGrid filing parties' regional compliance filings.[80] FERC's first compliance order recommended changes or clarifications on the following key areas: participation by non-public utility transmission providers; consideration of transmission needs driven by public policy requirements; non-incumbent transmission developer reforms; re-evaluation of the process for projects selected for cost allocation; and cost allocation methodology.

More notably, FERC's directives necessitated the development of the Order 1000 Functional Agreement by and among the jurisdictional transmission providers that would provide for participation in the planning process by Governmental Non-Enrolled Parties. This agreement and the additional OATT revisions in response to the FERC directives were submitted on December 17, 2013. FERC issued its second compliance order on September, 18 2014,[81] which necessitated the development of the First Amended and Restated Order 1000 Functional Agreement. This agreement and subsequent OATT revisions were filed on November 17, 2014.

The primary issue currently under review by FERC involves the process for Governmental Non-Enrolled Parties to advise Enrolled Parties whether they will accept the share of cost allocations assigned to them.

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[80] FERC , "Order on Compliance Filings and Petition for Declaratory Order", 143 FERC ¶ 61,255.
[81] FERC, "Order on Rehearing and Compliance", 148 FERC ¶ 61,212.

In their latest compliance filings, the ColumbiaGrid filing parties stated that the transmission planning activities under the Order 1000 Functional Agreement were to commence on January 1, 2015.

### 4.5.1 Planning Process Overview

The ColumbiaGrid regional planning process is performed on a biennial planning cycle. The ultimate deliverable of the planning process is the Biennial Transmission Expansion Plan that looks out over a ten-year planning horizon and identifies the transmission additions necessary to ensure that the planning parties can meet their commitments to serve load and transmission service commitments. The biennial plan is informed by annual system assessments, results from Study Team efforts, and studies performed by the individual planning participants. While certain time periods and deadlines are established for aspects of the regional planning process, many of the planning activities are performed in a flexible, iterative, and non-sequential manner.

For the first time in 2015, ColumbiaGrid will perform the planning activities developed for compliance with Order 1000. As such, in many cases, only general descriptions of ColumbiaGrid's proposed regional planning activities as they relate to Order 1000 are provided in the subsequent sections.

### 4.5.2 Annual System Assessment

Each year ColumbiaGrid performs a system assessment to determine whether or not the planned transmission grid can meet established federal, regional, and local reliability standards and to identify Order 1000 Needs. Prior to conducting the system assessment and in Quarter 1 of each year, ColumbiaGrid holds a public meeting to discuss potential Order 1000 Needs with the planning parties and stakeholders. Any interested person can submit to ColumbiaGrid items that should be considered as potential needs prior to this meeting, including those driven by reliability requirements, economic considerations, or public policy requirements.

An approximate timeline for the system assessment is shown in Figure 17.

**Figure 17: ColumbiaGrid System Assessment Timeline**

**November**

- Select Base Cases
- Review Ten Year Plan

**December**

- Update Base Topology
- Finalize Ten Year Plan

**January**

- Provide & Incorporate Ten Year Plan Project Files
- Adjust Loads, Resources , & Interchanges
- Review and Finalize Study Cases
- Receive Order 1000 Potential Needs suggestions

**February**

- Provide TPL Contingency & Automatic Action Files
- Develop Contingency Lists

**March/April**

- Process & Review Contingency Results
- Evaluate Order 1000 Potential Needs

**May**

- Prepare System Assessment
- Identify Order 1000 Needs
- Prepare Need Statement

**June**

- Approve System Assessment
- Recommend Study Teams for Proposed & Order 1000 Needs

***Source**: ColumbiaGrid 2015 System Assessment Draft Study Plan*

Power flow models for one-year, five-year, and long-term (eight to ten-year) planning horizons and seasonal loading conditions are created for the system assessment. A mixture of seasonal loading conditions is selected for study in order to test the adequacy of the transmission system under a wide variety of future system conditions. For example, in the 2014 System Assessment, a long-term light autumn base case was studied to reflect a light load condition with significant wind generation in operation, in addition to seven other more typical system conditions as shown in Table 9. The light autumn case reflects a typical operation scenario for the Northwest that has the potential for introducing reliability issues that would have otherwise been missed if ColumbiaGrid only studied system conditions during more typical system conditions (e.g. peak load).

**Table 9: ColumbiaGrid 2014 System Assessment Studies**

| Base Case No. | Description |
|---|---|
| 1 | 2015 Heavy Summer |
| 2 | 2015-2016 Heavy Winter |
| 3 | 2015 Light Summer |
| 4 | 2019 Heavy Summer |
| 5 | 2019-2020 Heavy Winter |
| 6 | 2022 Light Autumn |
| 7 | 2024 Heavy Summer |
| 8 | 2023-2024 Heavy Winter |

Recently approved WECC power flow base cases that closely correspond to the current system topology and desired seasonal system conditions are used as a starting point to create the ColumbiaGrid cases. ColumbiaGrid has scheduled the model building process to commence at approximately the same time as WECC completes their annual operating base cases to ensure the most up-to-date system topology is available in the cases selected by ColumbiaGrid. The base topology, loads, and generation patterns for all the other ColumbiaGrid planning cases are reviewed and updated with information provided by the planning parties and stakeholders to be consistent with the study parameters identified in the system assessment study plan. All modeling assumptions, including any changes made to the WECC cases by ColumbiaGrid, are documented in the System Assessment and Biennial Transmission Plan report.

### *Ten-Year Plan*

The ColumbiaGrid Ten-Year Plan is a list of committed projects identified by the planning participants as being needed within the planning horizon to serve load, integrate new resources, or facilitate economic transfers of energy. These projects are typically in the permitting, design, or construction phases of development. Once the Ten-Year Plan is completed, the power flow base case models are updated to be consistent with the plan.

### 4.5.3 Order 1000 Needs

Once the study models have been completed, the system assessment is conducted using power flow tools to simulate system outages and compare system performance against all applicable NERC, regional, and owner-adopted planning standards and criteria.[82] Any deficiencies in meeting the reliability standards in more than one planning participant's system are noted and evaluated to determine if further regional analysis is required, including sensitivity analysis, or if a plan to mitigate the need should be addressed through Study Teams.

Any potential Order 1000 Needs identified during the annual Order 1000 Needs meeting are vetted during the system assessment process. Order 1000 Needs are those of an Order 1000 Enrolled Party for transmission facilities in the Region, and include those driven by reliability requirements, addressing

[82] Other types of studies, including transient and voltage stability studies, may be conducted as part of sensitivity studies.

economic considerations, or driven by public policy requirements.[83] In selecting from among potential Order 1000 Needs to identify those needs for which solutions will be evaluated, ColumbiaGrid will consider a number of factors related to the identified needs including the feasibility of addressing the potential need and the extent to which addressing the potential need will address other potential needs. For each need validated and selected for further evaluation, ColumbiaGrid, in coordination with the planning parties and stakeholders, will develop one or more conceptual transmission or non-transmission solutions to meet the need. A summary of the identified Order 1000 Needs and conceptual solutions is summarized in Order 1000 Need Statements. The Final System Assessment Report reflects Order 1000 Needs identified and the Order 1000 Need Statements that are to be further evaluated.

Needs identified for PEFA parties not also party to the Order 1000 Functional Agreement are also identified in the System Assessment Report and are evaluated using a similar process as described for Order 1000 Needs, but are not eligible for Order 1000 cost allocation.

### 4.5.4 Evaluating Proposed Solutions

Plans to address needs documented in the Order 1000 Need Statements are more fully developed through Study Teams. Participation in the Study Teams is open to the planning parties, state agencies, and other interested stakeholders, except where such open participation must be restricted to protect confidential information or CEII. Possible solutions to identified needs may be conceptual solutions proposed by ColumbiaGrid staff, solutions proposed by any Study Team participant, or solutions proposed and submitted by Enrolled Parties or ITP Proponents. To be evaluated by the Study Team, all proposals for an identified need must be submitted within 30 days of the issuance of the Final System Assessment Report and must meet all applicable information requirements.

Several factors will be used to evaluate proposed solutions, including non-transmission alternatives, to the identified Order 1000 Needs including: feasibility, economics, effectiveness, and consistency with applicable state, regional, and federal planning requirements and regulations. Once a Study Team in consultation with the ColumbiaGrid staff has identified a proposed solution for an Order 1000 Need, a final Study Team report will be prepared. Cost allocation may be performed on the solutions identified in the final Study Team reports if they are regional or interregional and determined to be a more efficient or cost-effective solution to the need. Such projects are determined to be Order 1000 Eligible Projects, and may receive an Order 1000 cost allocation if the Enrolled Party or ITP Proponent that is the sponsor of the project submits a request for cost allocation and the Board approves the request.

Study Team activities are an ongoing process and may not conclude in the same planning cycle in which the Study Team was initiated.

[83] ColumbiaGrid will also identify needs for transmission facilities on the transmission systems of any Governmental Non-Enrolled Parties as part of the system assessment process, and will identify solutions for those needs in the same way as is described for Order 1000 needs. To the extent that a Governmental Non-Enrolled Party is determined to be a beneficiary of a transmission project proposed for selection in the regional transmission plan for purposes of cost allocation, however, that party will have the opportunity to accept or not accept the proposed cost allocations assigned to it. The process for doing so is currently under review by FERC.

### 4.5.5 Economic Modeling

ColumbiaGrid initiated an Economic Planning Study (EPS) effort in 2013 as part of its annual study program to evaluate future system performance using production cost modeling software. A Study Team was formed to oversee the EPS effort and was open to any interested party. Two rounds of economic planning studies have been completed by the Study Team to-date, including a model benchmarking exercise and an evaluation of future alternative resource replacement scenarios.

The first round of economic studies completed by the EPS Study Team in the second quarter of 2014 focused on establishing a methodology and process for conducting economic studies using the ABB GridView™ production cost modeling tool. As part of their initial efforts, ColumbiaGrid created a production cost model dataset reflecting 2010 system conditions to be used to benchmark model output against historical system operation. The WECC-TEPPC 2010 dataset was used as a starting point for ColumbiaGrid's backcast dataset. Results from the initial TEPPC dataset production cost simulation runs showed significant differences between modelled and historical system operation, so a number of modifications were made to the TEPPC dataset by ColumbiaGrid to improve the disparities observed. Major changes made to the TEPPC dataset included updating natural gas prices to reflect more accurate gas trading hub prices and local transportation fees; updating wind and solar production profiles to reflect 2010 operation; and modifying generator operating parameters (e.g. start-up costs, minimum run time, minimum down time, heat rates) in order to alter the dispatch stack to more accurately reflect the true commitment order of resources in the Pacific Northwest. After implementing these changes, ColumbiaGrid observed a significant improvement in the model results as compared to historical system operation.

During the third quarter of 2014, ColumbiaGrid initiated a second round of economic studies, this time focused on evaluating the impact of alternative future resource replacement scenarios for the planned retirement of the Boardman and Centralia coal plants. A total of nine scenarios were evaluated consisting of variations in the type and location of replacement generation assumed for Boardman and Centralia, as well as an additional retirement of Coalstrip units 1&2 in Montana.

The alternative retirement/resource replacement scenarios were evaluated in a 2017 planning horizon by applying incremental load, resource, and transmission changes to the refined 2010 backcast dataset built by ColumbiaGrid for benchmarking purposes. Major changes made to the 2010 dataset to create the future scenarios included:[84]

- The addition of planned new generation identified from utility Integrated Resource Plans or otherwise known to have received regulatory approval;
- the addition of incremental firm transmission scheduled to be energized by 2017 as identified in the TEPPC Common Case Transmission Assumptions and past ColumbiaGrid Biennial Plan reports; and
- the inclusion of 2017 load forecasts derived from a linear interpolation between 2010 loads and the TEPPC 2024 loads.

[84] ColumbiaGrid, "Economic Planning Study – Impacts from Coal Shutdown, Draft Study Report", March 27, 2015.

Results from the production cost simulations were focused on the impact of the alternative resource scenarios on Northwest exports, flows on major transmission paths internal to the Northwest, and generation dispatch patterns. No assessment of reliability impacts associated with any of the scenarios was conducted.

Going forward, ColumbiaGrid plans to maintain its production cost model dataset built for the backcast and future studies, but no information was found regarding the planned application of the dataset as it relates to identifying Order 1000 Needs.

### 4.5.6 Biennial Transmission Plan

The draft Biennial Transmission Expansion Plan documents all of ColumbiaGrid's regional transmission planning efforts over a given planning cycle. Major items documented within the Biennial plan will include: the ColumbiaGrid 10-Year Plan; all identified system needs, including Order 1000 Needs, evaluated during the planning process; results from the Annual System Assessments; a list of projects selected for purposes of Order 1000 cost allocation that are proposed for Board approval; a list of those projects that were not selected for cost allocation and an explanation underlying such a determination; and any other transmission solutions that were selected for inclusion in the plan.[85]

The Biennial Transmission Expansion Plan is developed from approximately July through December once the System Assessment is complete. In year one of the planning cycle, an update to the previously approved Biennial Plan may be issued depending on the results from the year-one System Assessments or recent Study Team efforts. The Board is responsible for approving the Biennial Transmission Plan and the cost allocation for any projects within the plan.

## 4.6 2015 Biennial Transmission Expansion Plan

The 2015 Biennial Transmission Expansion Plan was approved by the ColumbiaGrid Board on February 18, 2015. It reflects the ColumbiaGrid 10-Year Plan, results from the 2014 System Assessment and Economic Planning Studies, as well as Study Team Reports and other updates.

The 2014 System Assessment identified a number of areas of concern within the ColumbiaGrid planning region that affected more than one planning participant. Of the seventeen areas of concern identified, however, only three were new to the 2014 System Assessment. The remaining areas identified were either already being addressed by existing Study Teams or they were able to be assigned to an existing Study Team. Only one new Study Team was formed based on the results of the 2014 System Assessment.

With the conclusion of the 2015 Biennial Transmission Expansion Plan, ColumbiaGrid has initiated the 2015 System Assessment, which also kicks-off the first study program under the Order 1000 planning

[85] As part of the PEFA planning process, ColumbiaGrid may also convene Study Teams to address issues related to new transmission and interconnection service requests, single system projects, and capacity increase projects if requested by a planning party and if the issue has been determined to impact multiple transmission systems within the region.

requirements. ColumbiaGrid has held its first public Planning and Order 1000 Needs meeting, and is in the final stages of developing its study plan for the year.

## 4.7 Planning Coordination

Major transmission owners in the Pacific Northwest are invited to participate in the System Assessment process, and are further individually notified by ColumbiaGrid if results from the system assessment studies indicate an issue involving their systems. In these cases, they are invited to participate in the Study Teams to address the issue.

In addition to collaborating with non-planning party Transmission Providers, ColumbiaGrid has put into place a protocol in the ColumbiaGrid planning process for the collaborative involvement of the states and their agencies responsible for facility siting, utility regulation, and general energy policy within the ColumbiaGrid footprint. The protocol outlines the procedure for notifying interested state agencies of planning meetings and provides the opportunity for state agencies to request a consultation with ColumbiaGrid or its Board on matters of interest to the agencies.

A protocol has also been put into place for coordinating information between ColumbiaGrid and Indian tribes who may be impacted by the activities of ColumbiaGrid. The protocol establishes ColumbiaGrid's intent to consider the potential impact of decisions made as part of its planning process on tribal lands, and sets forth a procedure for determining when and how to notify a tribe regarding ColumbiaGrid's planning activities.

## 4.8 Stakeholder Process

ColumbiaGrid's regional planning process commences with an open meeting to solicit input from planning parties and stakeholders regarding potential system needs. The system assessment process, including the process to select modeling assumptions for the cases that are to be evaluated, continues in an open and transparent manner. Stakeholders are informed of the availability of system assessment results and are invited to comment on those results as the potential needs are distilled down into needs that will be subject to further evaluation. Study Teams formed to develop solutions to the identified needs are open to all interested stakeholders unless otherwise prevented due to confidentiality limitations. Finally, the process of finalizing the Biennial Transmission Plan is also conducted in an open stakeholder forum whereby comments are solicited and incorporated into the final Biennial Plan.

## 4.9 Links to Key Documents

2015 Biennial Transmission Expansion Plan

2014 System Assessment

2015 System Assessment Draft Study Plan

Economic Planning Study Draft Report

Second Amendment to the Planning and Expansion Functional Agreement (PEFA)

First Amended and Restated Order 1000 Functional Agreement

# Chapter 5: Interregional Coordination Efforts

The four western Planning Regions make varying degrees of reference to efforts to collaborate with neighboring Regions in the documentation of their regional transmission planning processes, as summarized in the preceding sections. Few formal, documented processes for coordinating planning activities across regions have been defined, and no single process for coordinating regional planning activities across the Western Interconnection has been defined. Rather, interregional coordination in the west has largely been a passive or ad hoc effort. Requests for input or participation from neighboring regions are either made when specific studies dictate the need to coordinate with a neighboring region, or general requests for input or participation are made but not associated with a commitment to respond.

In addition, to-date, many interregional coordination efforts have been facilitated at the WECC level through the Regions' use of WECC-compiled data or participation in TEPPC activities, where each Region (or in the case of WestConnect its sub-regions) has formal membership in the committee. Each region also participates in WECC's Regional Planning Coordination Group (RPCG), formerly called the Subregional Coordination Group, which is comprised only of members representing the TEPPC-recognized Regional Planning Groups including CAISO, NTTG, ColumbiaGrid and the WestConnect SPGs.[86] The goals of the RPCG are to facilitate transmission infrastructure planning among the RPCG members and to develop Common Case Transmission Assumptions for transmittal to TEPPC to be used as baseline assumptions for future planned transmission in the TEPPC studies. While the Regions' participation at WECC enables the coordination of regional planning data and assumptions to produce WECC datasets and models which are in turn used to perform regional planning activities, the requirements for interregional planning coordination set forth by Order 1000 are intended to achieve more focused coordination for planning activities conducted at the regional level.

## 5.1 FERC Order 1000 Interregional Compliance

FERC Order 1000 has placed an emphasis on formalizing the coordination of regional planning activities, requiring the four western Planning Regions to establish procedures with each of its neighboring transmission planning Regions to facilitate interregional transmission planning coordination.[87] In particular, Order 1000 established the following requirements to be included in the interregional transmission coordination procedures developed for compliance with the Order:

- A commitment to coordinate and share the results of each transmission planning region's regional transmission plans to identify possible interregional transmission facilities that could

[86] The Alberta Electric System Operator and British Columbia Coordinated Planning Group are also TEPPC-recognized Regional Planning Groups and members of the RPCG.
[87] FERC Order 1000 interregional requirements also set forth requirements for a common method or methods for the allocating of costs of a new interregional transmission facility selected for the purposes of cost allocation in the relevant planning regions' regional transmission plans. The focus of this report is on interregional transmission planning coordination procedures and not interregional cost allocation. As such, details regarding the Regions' compliance with Order 1000's interregional cost allocation requirements can be found in the Regions' interregional compliance filings made to FERC.

address regional transmission needs more efficiently or cost effectively than separate regional transmission facilities, as well as a procedure for doing so;

- Specific obligations for sharing, at least annually, transmission planning data and information;
- A formal procedure to identify and jointly evaluate proposed interregional transmission facilities;[88] and
- A commitment to maintain a website or e-mail distribution list for the communication of information related to the interregional coordination procedures.

Of note, FERC did not require the creation of a distinct interregional transmission planning process, the development of an interregional transmission plan, or formation of an interregional transmission planning entity.

The western Planning Regions responded to the interregional requirements set forth in Order 1000 by initiating a collaborative stakeholder process to jointly develop common procedures among all four regions to comply with the Order that would leverage the regional processes being concurrently developed. As part of this process, an Interregional Coordination Team (ICT) comprised of representatives from each Region was established to develop the necessary proposals to comply with the Order 1000 interregional requirements. The ICT elected to locate all materials related to the development of the interregional coordination procedures on the ColumbiaGrid website.[89] The first meeting of the ICT was held on October 1, 2012, and the first Order 1000 Interregional Coordination Stakeholder Meeting was held by the four Regions in November of 2012 to elicit initial stakeholder feedback with regard to the proposals for interregional coordination being developed by the ICT.

As the result of the collaborative efforts of the ICT — and with input provided by stakeholders at both regional and interregional-level discussions — CAISO, NTTG, and WestConnect participating transmission providers filed common tariff language outlining their commitment to and process for interregional transmission coordination and cost allocation on May 10, 2013. The ColumbiaGrid transmission providers submitted the common tariff language to FERC on June 19, 2013.

On December 18, 2014, FERC conditionally accepted the interregional compliance filings, subject to an additional compliance filing to be made by each Region. CAISO filed minor tariff changes on February 17, 2015 to address FERC's directive that it move from an avoided cost-only method to calculate regional benefits of an Interregional Transmission Project (ITP) to an avoided cost-plus other benefits method (which was consistent with their commission-approved regional cost allocation method). Subsequently, NTTG and WestConnect parties filed a transmittal letter notifying FERC that CAISO's proposed changes satisfied their compliance directive from FERC such that no change to the common tariff language was required. ColumbiaGrid parties were also able to satisfy FERC's December compliance directives via a

[88] An interregional transmission facility was defined by FERC in Order 1000 as "one that is located in two or more transmission planning regions."
[89] https://www.columbiagrid.org/O1000Inter-overview.cfm

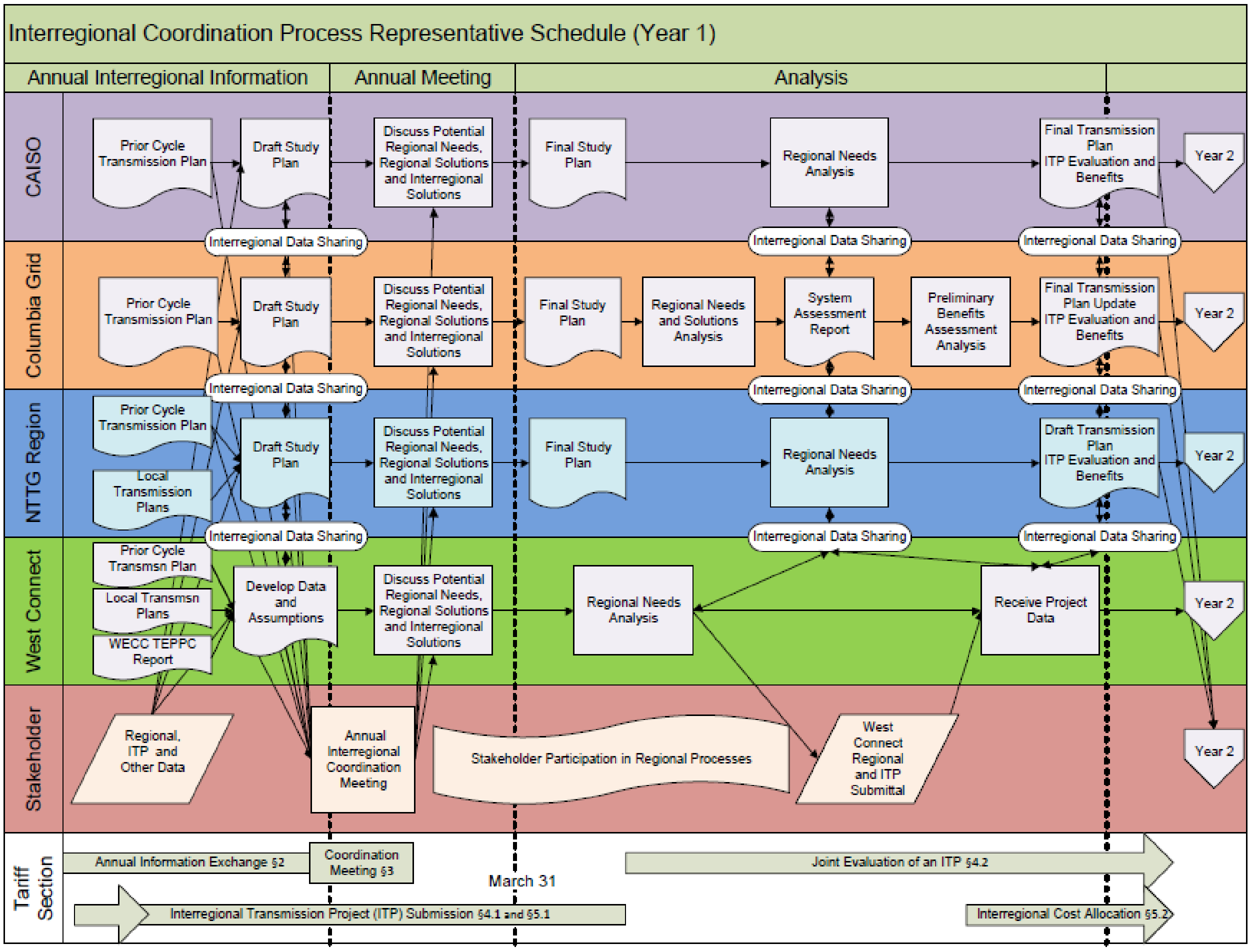
transmittal letter only.[90] As such, the effective date for Interregional Order 1000 for CAISO, NTTG and WestConnect participants has been set to October 1, 2015, and January 1, 2015 for ColumbiaGrid filing parties.

## 5.2 Interregional Planning Coordination Process Overview

The interregional planning coordination and cost allocation process developed to serve as the common coordination process for all four Regions is illustrated in Figure 16 and Figure 17. This diagram was submitted with the interregional compliance filings and illustrates the individual regional transmission planning processes developed as part of the regional compliance efforts, as well as the planned flow of information between the Regions. In addition, discrete interregional coordination data sharing activities are called out in oblong bubbles on the diagrams, and occur throughout the regional planning processes based on regional process milestones and timelines. It should be noted that the Regional transmission planning processes may have changed from what is presented in these diagrams, as they were created while many of the planning processes for compliance with the Order 1000 regional planning requirements were still either under development or under consideration by FERC. At the same time, the regions have not issued any updates to this diagram.

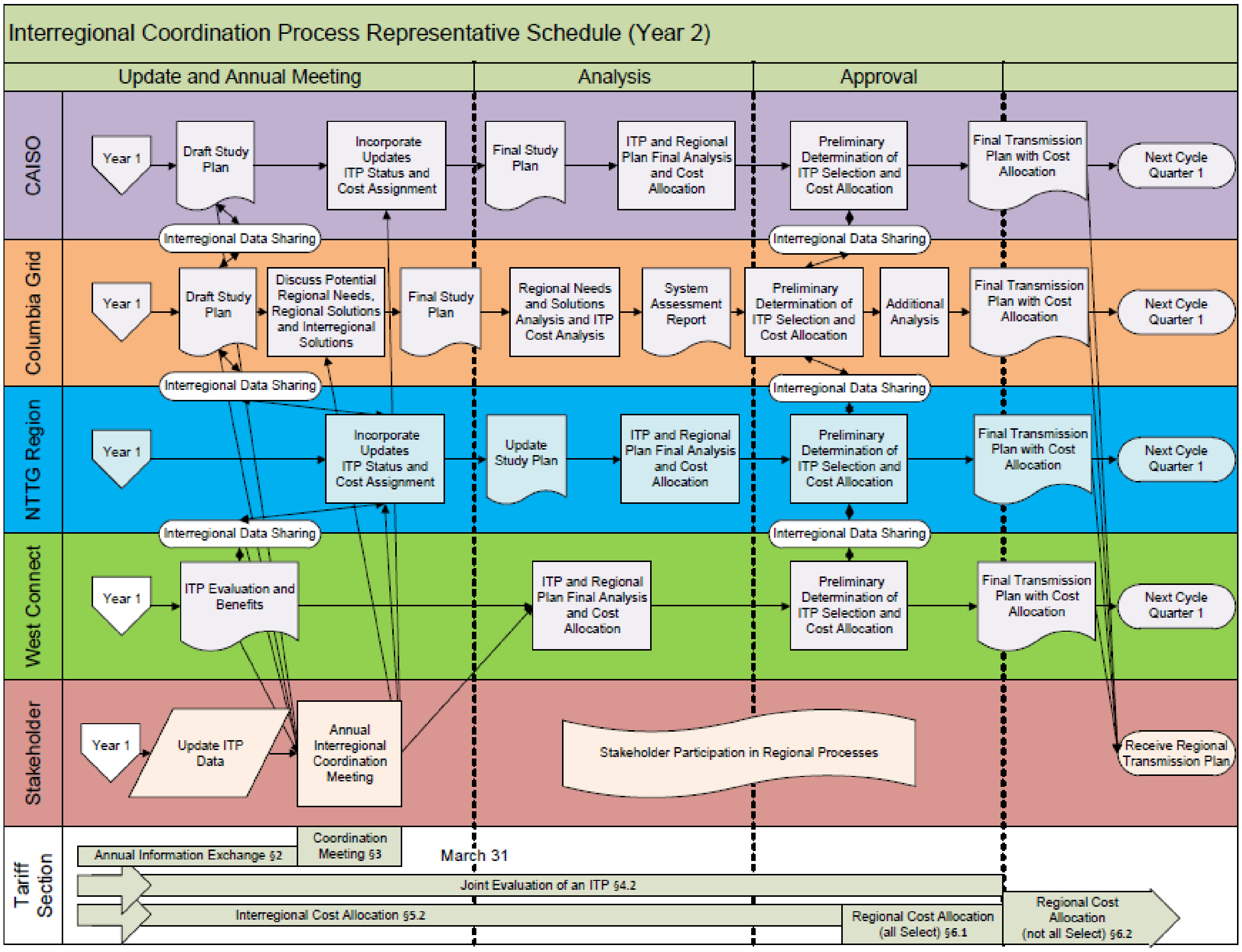
[90] ColumbiaGrid filing parties were directed by FERC to clarify the status of the Fourth Restated PEFA, remove references to the Fourth Restated PEFA from their Attachment Ks, and establish an appropriate effective date for their Attachment Ks.

## Figure 18: Interregional Coordination Process - Year 1




***Source**: CAISO Interregional Common Tariff Language*

**Figure 19: Interregional Coordination Process - Year 2**




***Source**: CAISO Interregional Common Tariff Language*

Key aspects of the interregional coordination process include the identification and sharing of Annual Interregional Information, a commitment to participate in an Annual Interregional Coordination Meeting, and a process for identifying and jointly evaluating ITPs, including the process for cost allocation of the ITP, if applicable. These activities are described in greater detail below.

### 5.2.1 Annual Interregional Information

The interregional coordination process begins with the sharing of Annual Interregional Information which may include study plans or the underlying information that would be typically included in a study plan, initial study reports or system assessment results from the current or previous planning cycle, and the regional transmission plans from the previous planning cycle. This information is expected to be posted on the Regions' websites or otherwise made available to each Region prior to the Annual Interregional Coordination Meeting.

### 5.2.2 Annual Interregional Coordination Meeting

The Planning Regions will participate in the Annual Interregional Coordination Meeting to be held no later than March 31 of each year. Each planning region will take turns hosting the meeting and it will be an open stakeholder meeting.

During each Annual Interregional Coordination meeting, the Regions and stakeholders will have an opportunity to discuss the Annual Interregional Information, identify conceptual interregional solutions that may meet regional transmission needs that have been identified in the regional planning processes, and discuss the status of ITPs currently under evaluation or included in a previous cycle's transmission plan. The main topics for discussion at the Annual Interregional Coordination meetings will likely change from year to year due to the fact that the western regional planning processes are a combination of both annual and biennial processes and the Regions will be in different points within their regional planning processes from year to year. For example, at the time of the year 1 Annual Interregional Coordination Meeting shown in Figure 14 and Figure 15, NTTG will be in the process of developing its study plan and will have accepted project submittals for a new planning cycle. WestConnect will be in the process of developing its study plan for a new planning cycle. CAISO will also be in the process of developing its unified planning assumptions and study plan for a new planning cycle, and will be finishing work on the draft Transmission Plan for the previous planning cycle. ColumbiaGrid will also be developing its study plan for a new planning cycle and finalizing its Transmission Plan for the previous cycle.

At the time of the year 2 Annual Interregional Coordination Meeting, NTTG will be reviewing the results of its draft Transmission Plan and discussing possible additional studies to perform or other changes that should be made to its study plan for the same planning cycle. Similar to NTTG, WestConnect will be in the same planning cycle and will have just accepted project submittals for identified regional needs, which may have included the submission of ITPs. CAISO will be in the process of finalizing its comprehensive Transmission Plan for the planning cycle just completed and developing the unified planning assumptions and study plan for a new planning cycle, as will ColumbiaGrid.

### 5.2.3 Process for Joint Evaluation of ITPs

Whereas FERC had defined an interregional transmission facility in Order 1000 as "one that is located in two or more transmission planning regions," it was determined by the Regions in the course of developing the interregional coordination procedures that the phrase "located in" was unclear. For example, the Regions questioned whether "located in" referred to a facility that was connected to two neighboring planning Regions or a facility that simply crossed over a neighboring planning Region. As such, in the common tariff language developed for the interregional compliance filings, the Regions defined the term "Interregional Transmission Project," or ITP, to refer to a proposed new transmission project that would directly interconnect electrically to existing or planned transmission facilities in two or more planning regions and that is submitted into the regional transmission planning processes of all such planning regions.[91]

Critical to the process developed for the joint evaluation of ITPs is the requirement that an ITP sponsor submit the ITP into the regional planning process of each Planning Region in which the project would be electrically interconnected, per the submittal guidelines and timelines of each Region. Following the identification of a properly submitted ITP, each Relevant Planning Region will participate in the joint evaluation of the project.[92] The process for the joint evaluation of ITPs has not been fully defined, but each Relevant Planning Region is to confer with every other Relevant Planning Region regarding the ITP data, costs, study assumptions and methodologies. To the extent that Relevant Planning Regions identify any differences in the planned approach to the evaluation of the ITP, they will seek to resolve those differences before proceeding with the joint project evaluation.

If an ITP has requested interregional cost allocation, it must first be selected and eligible for cost allocation in each Relevant Planning Region's regional planning process. If an ITP undergoing joint evaluation was not selected for cost allocation in one or more Relevant Planning Region's regional plan, the Region making this determination will inform the other Regions of their conclusion, and that Region will no longer be required to continue with the joint project evaluation. At this point, the remaining Relevant Planning Regions will evaluate whether, without the participation of this Planning Region, the ITP remains selected in their regional plans for the purposes of interregional cost allocation. For an ITP to receive an interregional cost allocation, it must be selected for interregional cost allocation by at least two Relevant Planning Regions in their respective regional transmission plans.

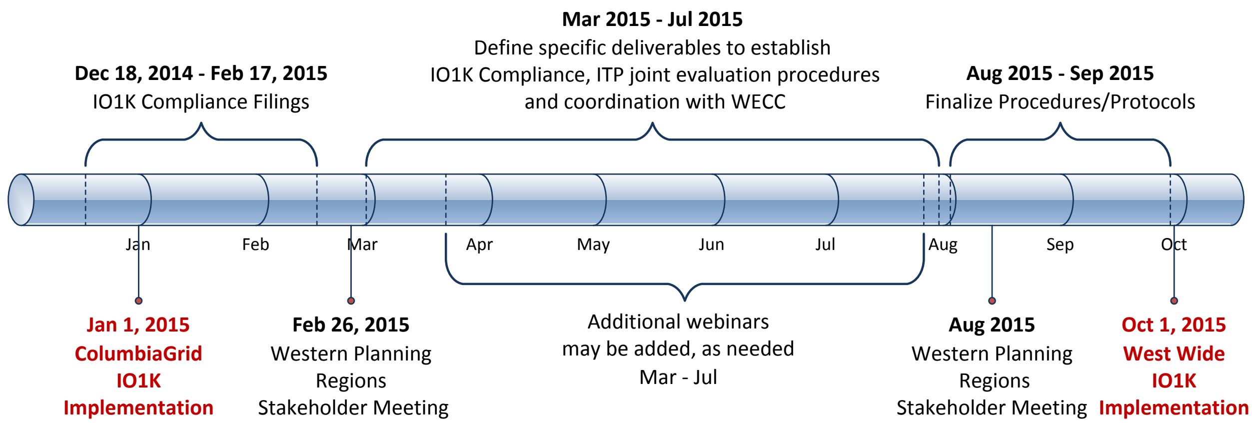
## 5.3 Next Steps for Interregional Coordination Efforts

On February 26, 2015 the four western Planning Regions held a public stakeholder meeting to present and discuss the status of, and plans for, the further development of the interregional coordination procedures. As presented, the Regions plan to further refine and document the joint ITP evaluation process and identify the mechanisms for conducting the interregional coordination process, including the best approach for the sharing of interregional information and the potential need for a common interregional email distribution list or website. A timeline for the planned implementation of the Order 1000 interregional coordination process, including opportunities for stakeholder input, is outlined in Figure 16.

[91] CAISO, "Western Interconnection- Order No.1000 Interregional Compliance Filing". http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13257122

[92] A "Relevant Planning Region" is defined in the Common Interregional Tariff Language as the Planning Regions that would directly interconnect electrically with the ITP, unless and until such time as a Relevant Planning Region determines that ITP will not meet any of its regional transmission needs, at which time it shall no longer be considered a Relevant Planning Region.

**Figure 20: Interregional Order 1000 Implementation Timeline**




***Source**: February 26, 2015 Western Planning Regions Coordination Meeting*

Based on the effective date for the west-wide implementation of the interregional coordination process, the first Order 1000 Annual Interregional Coordination Meeting will be held sometime during the first quarter of 2016. At this time, WestConnect will have just completed an abbreviated Order 1000 regional planning cycle and will be initiating its first full biennial regional planning process for the 2016-2017 planning cycle. NTTG will be gathering data and preparing the study plan for its 2016-2017 planning cycle. CAISO will be in the process of finalizing its comprehensive 2015-2016 Transmission Plan, and developing the 2016-2017 unified planning assumptions and study plan. And finally, ColumbiaGrid will be preparing for its 2016 System Assessment and considering updates to its 2015 2016 Biennial Transmission Expansion Plan.

## 5.4 Link to Key Documents

CAISO Interregional Compliance Filing (Common Tariff Language)

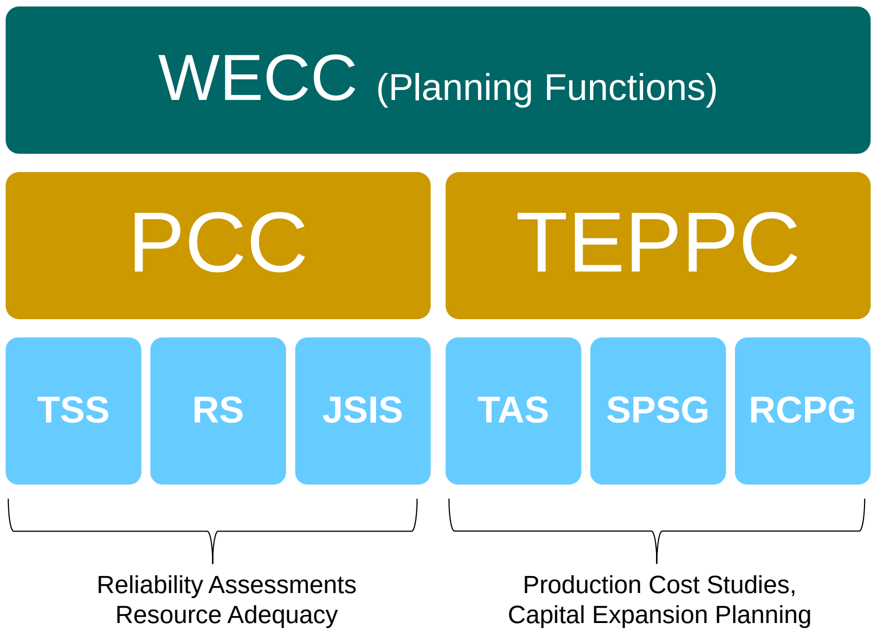
December 18, 2015 FERC Order on Interregional Compliance Filings

February 26, 2015 Western Planning Regions Coordination Meeting presentation

# Chapter 6: WECC Transmission Planning Overview

WECC is one of eight NERC-delegated Regional Entities responsible for developing, monitoring, and enforcing standards for the reliability of the Bulk Electric System.[93] In addition to its compliance monitoring and enforcement and standards development functions, WECC trains system operations personnel, monitors variable generation issues, and facilitates coordinated operating and planning activities. Many of WECC's functions are performed under a public, stakeholder-driven process, in coordination with WECC members and stakeholders through their participation in WECC committees. The committees associated with WECC's planning functions are illustrated in Figure 17.

**Figure 21: WECC Planning Committees**




## 6.1 Planning Coordination Committee

The PCC is one of five WECC Standing Committees[94] and was established in 1967 by the Agreement of the Western Systems Coordinating Council (WSCC), the predecessor to WECC. The purpose of the PCC is to advise and make recommendations to the WECC Board on all matters within the jurisdiction of WECC that pertain to maintaining the reliability of the Western Interconnection.[95] This is accomplished through evaluating potential future generation and load balance and the adequacy of the physical infrastructure (reliability planning) of the Bulk Electric System in the Western Interconnection. The PCC

[93] Prior to 2014 WECC was both the Regional Entity and Reliability Coordinator for the Western Interconnection. On January 1, 2014 Peak Reliability was formed as an independent company to serve as the Reliability Coordinator and Interchange Authority for the Western Interconnection going forward. FERC issued final approval of the bifurcation of WECC on February 12, 2014.

[94] The WECC Standing Committees include: the Member Advisory Committee, WECC Standards Committee, Planning Coordination Committee, Operating Committee, and Market Interface Committee.

[95] WECC, "Planning Coordination Committee Charter", October 13, 2011.

together with its subcommittees[96] and work groups achieves its purpose through coordinated planning efforts which support not only WECC's mission but the individual efforts of its members and stakeholders, including the western Planning Regions, to maintain a reliable electric power system.

The PCC's coordinated planning efforts are most significantly implemented through the WECC Annual Study Program and the Project Coordination and Path Rating processes.

### 6.1.1 WECC Annual Study Program

The WECC/PCC Annual Study Program is conducted to provide an ongoing reliability assessment of the Western Interconnection as it exists today and as it is planned over the next ten years. The study program consists of two primary activities: the development of steady state and dynamic base case models, and an annual assessment of system performance based on selective disturbances simulated using the base case models.[97] In a typical study program, eleven base cases are developed including five operating cases, three scenario cases, one five-year summer planning case, one five-year winter planning case, and one 10-year planning case (alternating between a winter and summer case). The cases developed for a particular study program may vary slightly from this typical set of cases based on the needs of the members. The 2015 Study Program includes the following base cases:[98]

- Typical base cases
    - Operating base cases
        - 2015-16 Heavy Winter
        - 2015-16 Light Winter
        - 2016 Heavy Spring
        - 2016 Heavy Summer
        - 2016 Light Summer
    - Five-year base cases
        - 2021 Heavy Summer
        - 2020-21 Heavy Winter
    - Ten-year base cases
        - 2025-26 Heavy Winter
        - 2026 Heavy Summer
- Scenario base cases

[96] The PCC subcommittees include the Reliability Subcommittee (RS), the Technical Studies Subcommittee (TSS), and the Joint Synchronized Information Subcommittee (JSIS). JSIS is joint subcommittee of both the PCC and WECC's Operating Committee.
[97] WECC, "WECC Guideline: Annual Study Program Scope of Work", March 18, 2005.
[98] WECC, "SRWG 2015 Base Case Compilation Schedule", February 27, 2015.

- 20xx Planning Region 10-year Light Load Case[99]
- 2018 Heavy Summer w/high imports into Southern California

A base case compilation schedule is developed which identifies the general timelines for the completion of each base case as well as the data submittal and data review milestones to compile each case. Data used to compile the WECC base cases is provided to WECC by Planning Coordinators[100] who receive data from the western transmission owners, transmission planners, generator owners, and resource planners. Data requirements and reporting procedures necessary to support the creation of the WECC base cases are detailed in the WECC Data Preparation Manual (DPM) for Interconnection-wide Cases. The data requirements and reporting procedures set forth in the DPM are governed by a NERC reliability standard, MOD-032: Data for Power System Modeling and Analysis. This standard specifically requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the interconnection-wide base case building process in their interconnection.[101]

Once the WECC staff has compiled the data to create the base cases, the compiled case will be tested using steady state and transient stability analysis techniques, and both the compiled case and the results of the test simulations will be posted for review. After incorporating data corrections and comments received from members during the previous review phase, the WECC staff will re-run the steady state and transient stability analyses and post the simulation results and the final compiled case to the WECC website. At this point, the cases are taken and used by utilities, merchant and independent transmission developers, all four of the western Planning Regions, and anyone else (subject to WECC's NDA requirements) who is interested in analyzing the transmission system of the Western Interconnection.

In 2013, WECC took delivery of the Base Case Coordination System (BCCS), which it had developed for the purposes of automating the base case creation process via a web-accessible, centralized database of planning data. Since that time, WECC has been working with the BCCS vendor to fix several major program bugs, and it is not known when the BCCS will be ready for implementation to replace the existing base case creation process.

### 6.1.2 Project Coordination and Path Rating Processes

The PCC has the responsibility for oversight and review of the Project Coordination and Path Rating Processes. The Project Coordination Process is used during the initial development phase of a significant transmission project (>200 kV unless it receives a waiver by the PCC chair) and serves to inform others of the opportunity to participate in or review a project. It is intended to avoid duplication of projects and

[99] This case will be a 10-year case and was specifically requested by the western Planning Regions as needed to support their regional transmission planning processes in 2016.

[100] The term "Planning Coordinator" is defined in the NERC Reliability Functional Model as the "functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans and resource plans within a Planning Coordinator area, and coordinates those plans with adjoining Planning Coordinator areas."

[101] NERC MOD-032-1 – Data for Power System Modeling and Analysis http://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-032-1.pdf

to foster the development of a broad perspective among all stakeholders in the project planning process.[102] Sponsors of all significant transmission projects are required to prepare a Project Coordination Report. A waiver can be obtained if the purpose of the transmission project is to serve local load or the project does not have a significant impact on the operation of the Western Interconnection. A project completes the process upon approval of the Project Coordination Report by the PCC.

The purpose of the Path Rating Process is to provide a formal process for a project to attain an Accepted Rating[103] and demonstrate how it will meet NERC Reliability Standards and WECC Criteria. This process is for planned new facility additions and upgrades or the re-rating of existing facilities. It requires coordination through a review group comprised of the project sponsors and representatives of other systems that may be affected by the project. Any project may seek a path rating under the WECC Path Rating Process on a voluntary basis.[104] A project may be required to complete the Path Rating Process if it meets certain criteria, including if the condition limiting the transfer capability of the project is on another system and the affected system owner requests that the path be rated.

## 6.2 Transmission Expansion Planning Policy Committee (TEPPC)

TEPPC was established in 2006 as a Board-level committee and serves four primary functions:[105]

- Oversee and maintain a public transmission expansion planning database;
- Develop, implement, and coordinate planning processes and policy;
- Conduct transmission planning studies; and
- Prepare interconnection-wide transmission plans

This last function was introduced in 2010 when WECC received a grant from the U.S. Department of Energy under the provisions of the American Recovery and Reinvestment Act to expand its transmission expansion planning functions. Through this funding, WECC established the Regional Transmission Expansion Planning (RTEP) project which served to expand the breadth and depth of stakeholder involvement in WECC's transmission planning activities, add new tools for transmission planning, and create interconnection-wide transmission plans. WECC published its first ever 10-Year Regional Transmission Plan in 2011, and both 10-Year and 20-Year interconnection-wide transmission plans in 2013. WECC does not have authority or jurisdiction over the siting, permitting, or constructing of transmission lines, and as such these plans were informational in nature and served to advise and guide decision makers in the Western Interconnection regarding the potential for and implications of future transmission and generation investment.

[102] WECC, "Project Coordination, Path Rating and Progress Report Processes", July 15, 2014.
[103] A path rating reflects the transfer capability of the path. An Accepted Rating is a path rating that has been reviewed and accepted by WECC members following the conclusion of the Path Rating Process and will be the rating of the project when it is put into service.
[104] An Accepted Rating affords a project sponsor some protection against erosion of established capacity of this facility when further expansion of the interconnection is proposed or new limitations are discovered.
[105] WECC TEPPC website: https://www.wecc.biz/TEPPC/Pages/Default.aspx

In addition to the interconnection-wide transmission plans, TEPPC has developed and distributed many different work products in the form of public databases of planning data and models. These work products were developed by the WECC staff with extensive input and review provided by TEPPC members and stakeholders, which includes subject matter experts from the WECC member utilities, state agencies, non-governmental organizations, and national laboratories. Some of the more significant work products include:

- A 10-Year economic planning database (TEPPC Common Case) to reflect an "expected future" for the Western Interconnection. Data and assumptions reflected in this database include load, resource and transmission assumptions, wind and solar production profiles, hourly annual load shapes, hydro modeling information, and fuel price assumptions. These assumptions are compiled from information submitted to WECC by the western utilities and from extensive input provided by other stakeholders engaged in energy-related activities throughout the west.
- A 20-Year capital expansion model built from the 10-year data and expanded to include additional resource and transmission infrastructure. Future resource and transmission investments are co-optimized within the model to meet various energy futures reflecting alternative assumptions for parameters such as load, fuel prices, technology costs, and environmental policies in a 20-year planning horizon.
- Wind and solar hourly production profiles for various aggregated resource locations throughout the Western Interconnection.
- Resource and transmission capital cost information and a cost calculator to enable a cost/benefit evaluation of alternative resource and transmission scenarios. This information is also used as input for the investment decisions identified in TEPPC's 20-year model.
- Preferred environmental data and an environmental data viewer and risk classification system to inform the identification and evaluation of transmission alternatives.

Collectively, these work products have served to inform and improve TEPPC's technical studies and have also been incorporated into the individual planning activities of the WECC members, including the western Planning Regions.

### 6.2.1 Technical Studies

The technical studies performed by TEPPC are identified as part of an open season study request window, in which any interested stakeholder is invited to submit study requests for consideration by TEPPC. TEPPC reviews and prioritizes the study requests to develop an annual study program. Results from these studies are compiled, and at the end of each biennial planning cycle they are reported in the 10-year and 20-year transmission plans.

TEPPC's 10-year technical studies are performed using the ABB GridView™ production cost simulation tool, which is the same tool used by the western Regions to perform their economic studies. Development of the data and assumptions used to create the 10-year studies is led by TEPPC's Technical Advisory Subcommittee and its Data, Modeling, and Study work groups. In addition to these groups, the Regional Planning Coordination Group (RPCG) — comprised of representatives from each of the western

Planning Regions, including representatives from Alberta and British Columbia — provides input into the TEPPC studies in the form of the Common Case Transmission Assumptions (CCTA). The CCTA is a list of transmission projects that meet criteria established by the RPCG such that they have a high probability of being constructed and in-service within the TEPPC planning horizon. These projects, together with existing transmission facilities, provide an assumed minimum transmission system starting point for TEPPC's studies.[106] The results from TEPPC's 10-year studies are used to assess the utilization and robustness of the expected transmission system in the 10-year planning horizon across a variety of alternative futures.

TEPPC's 20-year studies are performed using WECC's Long-term Planning Tool (LTPT), which was specially developed by WECC for its long-term transmission planning studies. The LTPT co-optimizes a set of generation and transmission expansions necessary to meet load (at least-cost) given a set of stakeholder-derived decision factors (e.g., environmental, policy, economic) and reliability-based constraints. Data assumptions and decision factors to be considered by the LTPT are developed collaboratively by TAS and the Scenario Planning Steering Group (SPSG). The SPSG, as well as the RPCG, were formed to help support the RTEP project. In addition to providing technical input (modeling parameters and scenario definitions) into the 20-year technical studies, the SPSG provides guidance to TEPPC regarding emerging policy, regulatory, environmental, and industry trends that may have a significant impact on transmission planning. The results from TEPPC's 20-year studies are used to show how long-term generation and transmission choices may respond to major changes in certain fundamental planning assumptions.

For a number of years, an obvious shortcoming of TEPPC's technical studies was the lack of any detailed assessment of the potential reliability implications of the scenarios developed by TEPPC, as well as the absence of any consideration of additional operational flexibility needed in scenarios reflecting high levels of renewable penetration. TEPPC has made strides to address these shortcomings by engaging with the National Renewable Energy Laboratory (NREL) to calculate and model hourly flexibility reserves based on the amount of wind and solar generation observed in the models. In addition, WECC, in collaboration with WIEB, has initiated an effort to better understand the need for power system flexibility under high renewable penetration levels in the planning horizon, and to integrate and expand planning tools to address the need for system flexibility. WECC and WIEB have engaged with NREL and E3 to study operational flexibility needs using E3's Renewable Energy Flexibility Model (REFLEX). In addition to quantifying the need for operational flexibility, this study plans to investigate potential flexibility solutions and identify a means to incorporate this information into planning processes. This study is currently underway and is expected to be completed in May of 2015.

TEPPC is taking steps to address concerns regarding the reliability implications of the TEPPC studies as well. Most notably, TEPPC is working with NTTG and ABB to investigate the possibility of performing a "round-trip" assessment of the TEPPC studies. The "round-trip" approach is used by NTTG in its regional transmission planning process and involves exporting hours from the production cost model for study using the power flow model. Such an approach establishes consistency between power flow and

[106] WECC, "RPCG 2024 Common Case Transmission Assumptions", June 2, 2014.

production cost model analyses, thereby enabling the evaluation of system reliability under a range of stressed system conditions as identified by a production cost model.

### 6.2.2 TEPPC 2015 Work Plan

Since receiving the DOE grant in 2010, WECC has significantly expanded its transmission expansion planning activities (technical analyses and reporting) to meet the requirements of the grant as well as the growing need for coordinated and comprehensive transmission planning and planning related information. The DOE grant funding ended on December 31, 2014, and in preparation WECC initiated an effort to re-evaluate the TEPPC process and products it created. As part of this re-evaluation, WECC began soliciting feedback from its members and stakeholders to determine what direction it should take with regard to study reporting and whether there continues to be a need to produce an interconnection-wide transmission plan on a biennial basis. WECC staff also began requesting feedback regarding how the various TEPPC work products were used by the WECC members and stakeholders, and whether there was value in the continued upkeep and distribution of these work products.

As a result of the feedback received, WECC proposed, and TEPPC has approved, a hybrid approach toward conducting and reporting on studies moving forward. WECC has outlined this approach in the drafting of the TEPPC 2015 Work Plan, which has also received TEPPC approval. The primary elements of this work plan consist of:[107]

1. Maintaining a public database of planning data and models;
2. Facilitating an Interconnection-wide transmission expansion planning process;
3. Performing and reporting on technical, reliability and economic analyses of the Western Interconnection; and
4. Preparing a bi- or triennial Interconnection-wide reliability assessment report.

As compared to previous TEPPC efforts, item 1 involves continuously updating the TEPPC production cost database rather than freezing it while TEPPC performs its technical studies, as was the practice in the past. Supporting datasets, including the TEPPC capital cost information and environmental data, will also continue to be updated, but according to their existing update processes.

With regard to the reporting of TEPPC's technical studies, WECC will release individual study reports when they are completed rather than waiting to release a final report of all the studies conducted for the biennial study program.

Finally, rather than eliminating the interconnection-wide transmission plan reports, WECC has proposed that a report could be issued biennially or triennially that focuses not just on the activities and outcomes of the TEPPC process, but on all WECC work products, and could also include a summary of the western Planning Regions' activities and products, and/or a summary of overarching policy and planning observations. The appropriate content for this report is still under discussion, but its goal would be to present an interconnection-wide perspective on planning issues.

[107] WECC, "TEPPC 2015 Work Plan", February 2, 2015.

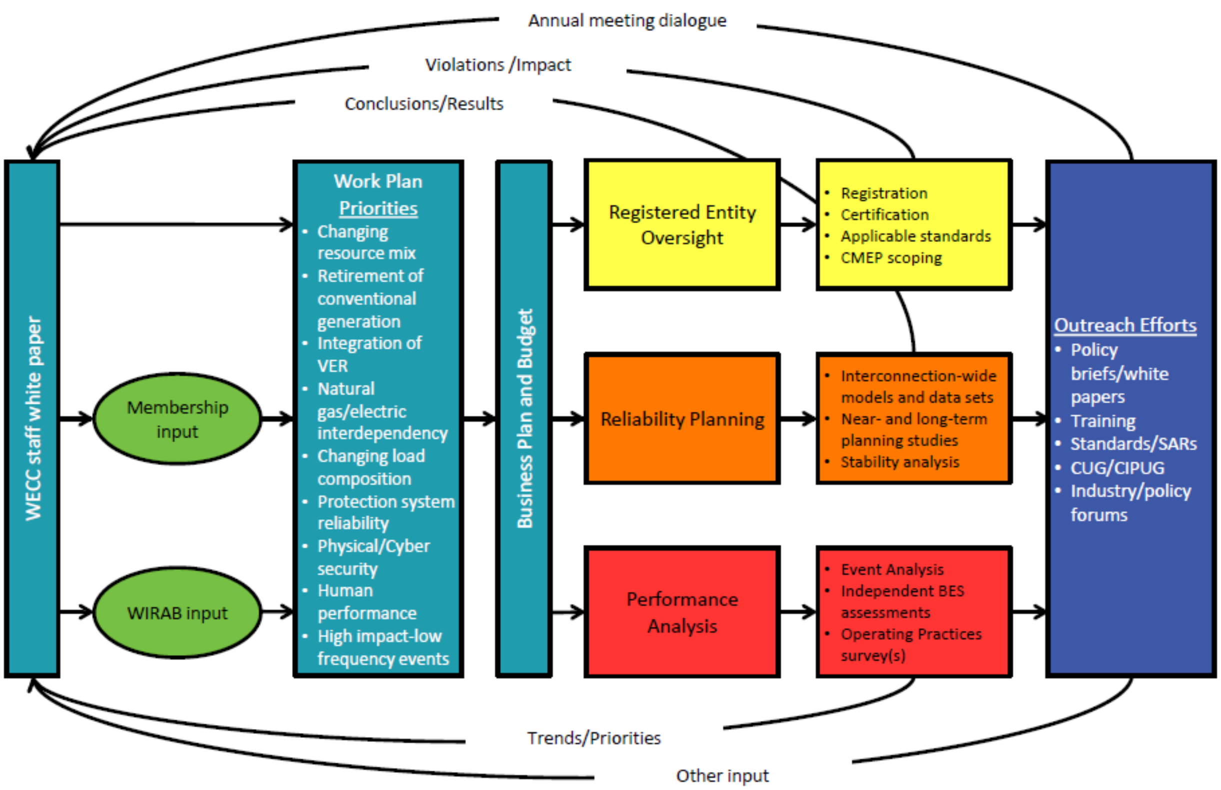
### *2015 Study Program*

A component of the TEPPC 2015 Work Plan will continue to be an annual study program informed by the annual open season study request window. The study request window for the 2015 study program closed on January 31, 2015. In order to improve the efficiency of the Study Program, TEPPC has proposed to sort study requests into core thematic areas and to select a reduced number of very high priority studies for the 2015 Study Program. TEPPC is still in the process of finalizing its 2015 Study Plan, but high priority studies identified in the draft study plan forwarded to TEPPC for approval includes a 2026 Common Case, 2036 Reference Case, a series of 10-year load, hydro, gas price, and carbon price sensitivities, and a series of high renewable and coal retirement scenarios.

## 6.3 Integrated Reliability Assurance Model

In 2014, WECC introduced the Integrated Reliability Assurance Model (IRAM). The IRAM was designed by WECC as a means to identify, analyze and address the top reliability challenges facing the Western Interconnection.[108] As such, the IRAM will be used to set priorities and integrate the activities of WECC to address the agreed-upon priorities. This approach is illustrated in Figure 18.

**Figure 22: WECC Integrated Reliability Assurance Model**




***Source**: WECC*

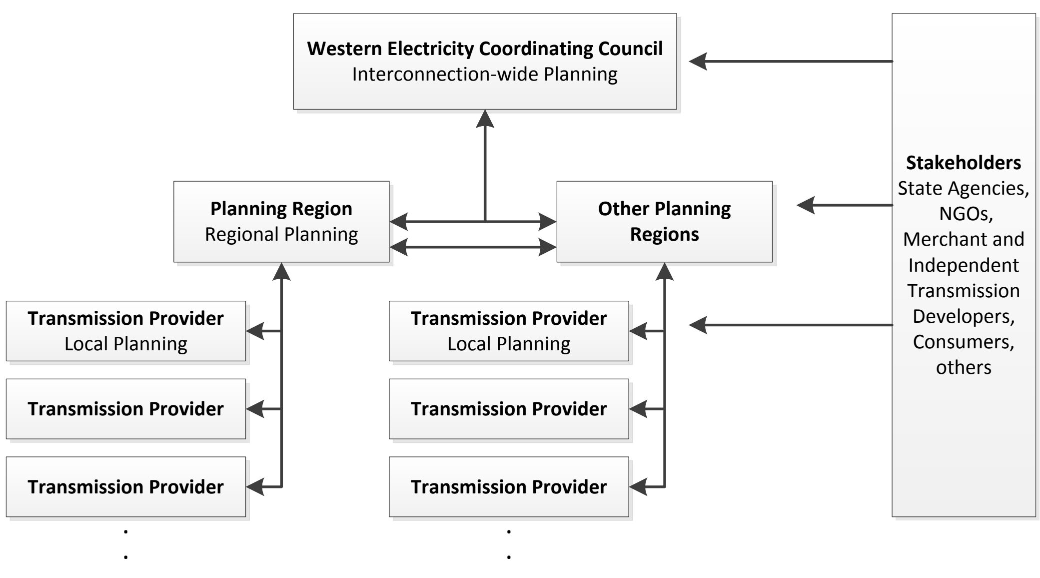
[108] WECC, "Reliability Challenges White Paper", October 2, 2014.

WECC's recent analysis of the Environmental Protection Agency's (EPA's) Clean Power Plan illustrates its new approach of using cross functional teams to address high priority issues with the potential to significantly impact the generation and transmission industry in the Western Interconnection. Phase 1 of WECC's analysis was published in September of 2014 and outlines results from a preliminary analysis of the potential reliability impacts of the EPA's assumptions regarding the building blocks (coal plant efficiency, increased natural gas utilization, renewable and nuclear power, and energy efficiency) that could be used to achieve the proposed emission reduction targets. [109] WECC's analysis was informed by a resource adequacy assessment, production cost simulation, and system power flow stability studies, and leveraged existing WECC work products including the TEPPC Common Case dataset and the PCC base cases. Results were focused at the interconnection-wide level, and some state-level summaries were also provided. As WECC moves into Phase 2 of its analysis of the Clean Power Plan, it plans to perform additional technical analysis with a focus on the reliability implications of potential or conceptual state compliance plans.

## 6.4 WECC and Planning Region Coordination

The West has a long history of collaborative transmission planning efforts that even predate Order 890, but Order 890 served to formalize a multi-tiered coordinated planning process structure in the Western Interconnection. As illustrated in Figure 21, this structure consists of the individual western Transmission Providers, Regional Planning Groups, and WECC. Each tier of this coordinated planning structure is further informed by input and direction provided by a broad range of stakeholder groups including state regulators, non-governmental organizations, energy consumers, national laboratories, and other energy stakeholders.

**Figure 23: Western Interconnection Transmission Planning Coordination**




[109] WECC, "EPA Clean Power Plan, Phase 1 – Preliminary Technical Report", September 19, 2014.

Transmission Providers are responsible for acting on requests for transmission service and assessing future load and resource needs to properly plan for new and upgraded transmission infrastructure to maintain the reliable and efficient use of the electric grid, all in accordance with well-defined procedures consistent with state-level, NERC, and FERC standards and requirements.  When transmission system needs arise that have the potential to impact more than one Transmission Provider, Regional Planning Groups provide the forum for regional transmission planning coordination.  Order 1000 has increased the role of Regional Planning Groups as a forum for Transmission Providers to meet their expanded planning obligations to participate in a robust, open and transparent regional and interregional planning process that specifically identifies more efficient or cost-effective regional or interregional transmission solutions and provides a mechanism for regional/interregional cost allocation.  At the interconnection-wide level, WECC provides a forum for the coordination of local, regional, and interconnection-wide issues, which serves to achieve WECC's purpose as the Reliability Assurer for the Western Interconnection.

Importantly, transmission planning information flows up to WECC from local Transmission Providers and Regional Planning Groups to be compiled and used for interconnection-wide assessments of the reliability of the Western Interconnection, and then flows back down to inform both regional and local planning activities.  As an example, WECC's Annual Study Program serves to coordinate transmission planning data and models from the western Transmission Providers for use in all levels of reliability planning activities: local, regional, and interconnection-wide studies.  The Project Coordination and Path Rating processes serve to inform others of future transmission expansion plans, and provide opportunities for multiple parties to participate in transmission project development.  The TEPPC process has created a forum for conducting economic studies of interconnection-wide transmission system congestion, and more broadly, the assimilation of an extremely broad range of transmission planning considerations including implications of public policy decisions, energy efficiency, distributed generation, demand-side management, environmental considerations, and resource procurement alternatives.  Notably, TEPPC is the only forum at WECC that formally recognizes and coordinates with the western Planning Regions as independent entities (with the exception of CAISO who is also a Transmission Provider), providing the Planning Regions with formal TEPPC membership and encouraging their input and participation through the RPCG.  The Planning Regions have also formally recognized their coordination with WECC and TEPPC through their use of the WECC base cases and TEPPC production cost dataset in the documentation of their regional planning processes.

WECC's coordinated transmission planning activities are structured around the planning obligations and requirements of the local Transmission Providers and the Regional Planning Groups, as well as its own obligations as the Reliability Assurer of the Western Interconnection.  The Regional Planning Groups have also structured their processes to meet the planning obligations of their members and participants, and at the same time recognize the benefits of coordinating with WECC.  As planning obligations expand and/or evolve, however, the structuring of these individual processes must also evolve, requiring new attention to the scope and timing of the coordinated activities to ensure that they satisfy transmission planning obligations and are efficient and non-duplicative.

At the WECC level, the end of the DOE funding for the RTEP process prompted the need to review TEPPC's reporting functions and assess the value of its work products to determine the focus of its efforts in support of planning coordination going forward. The major elements of TEPPC's proposed 2015 Work Plan are those elements that were determined through stakeholder feedback to be the most valuable existing TEPPC work products, including the TEPPC production cost database. These will continue to be supported by WECC.

At the same time, WECC has also initiated a review of its governance and structure in accordance with section 4.9 of the WECC Bylaws (Section 4.9 Review). The scope of this review effort encompasses WECC's staffing and resources as well as the structure and operation of the WECC Board, membership, and committees, to ensure that WECC is able to effectively and efficiently fulfill its reliability mission.[110] The review will specifically address high-priority issues including the WECC committee roles, scope, and structure; the relationship between WECC's Member Advisory Committee and the members; and WECC's cost to its members.[111] The Section 4.9 Review will result in a set of recommendations presented to the WECC Board and members in September of this year.

At the regional planning level, all four western Planning Regions are now implementing their Order 1000-compliant regional planning processes, and are in the process of establishing the procedure for implementing the interregional coordination process requirements. The Regions' interregional coordination efforts, together with WECC's review efforts, have sparked a conversation regarding the scope of each entity's planning efforts and the proper structure and coordination of planning efforts among the entities. WECC coordination topics raised for discussion at the recent Western Planning Regions Coordination Meeting include:[112]

- Accuracy, consistency, transparency, confidentiality, and applicability of planning data, models, and assumptions used by the Regions and WECC;
- Elimination of duplicative planning efforts to avoid unnecessary conflicting results;
- Usefulness of results and reports; and
- Timeliness of data preparation and development of interconnection-wide scenario cases for use in regional planning process.

From the Regions' perspective, they can provide WECC planning data and assumptions used to conduct the regional and interregional planning processes as a means to inform WECC's transmission planning efforts (PCC and TEPPC) and IRAM process. The Regions further noted their interest to review and validate the results of WECC's analyses, and participate in the technical review committees formed to address specific focus areas identified in the IRAM process.

At the same time, the Regions acknowledged the benefit in the continued use of WECC's interconnection-wide power flow and production cost model base and scenario cases, as well as the application of WECC's specialized datasets (capital cost datasets, flexibility reserve calculations, short

[110] WECC, "Section 4.9 Work Group Scope," December 4, 2014.
[111] WECC Section 4.9 Review Work Group, Progress Report, February 13, 2015.
[112] Western Planning Regions Coordination Meeting presentation, February 26, 2015.

circuit data and models, etc.) to the regional and interregional planning processes that will serve to satisfy their member's regulatory obligations.

Both WECC and the Regions appear to be interested in addressing the coordination issues collaboratively, and are currently well situated to do so based on the timeline for WECC's Section 4.9 review, and the implementation schedule for the interregional coordination process – both efforts are set to conclude in the September/October timeframe.

## 6.5 Link to Key Documents

TEPPC 2015 Work Plan

WECC Reliability Challenges White Paper

WECC Section 4.9 Review Work Group, February Progress Report

EPA Clean Power Plan, WECC Phase 1 – Preliminary Technical Report

# Chapter 7: Regional Transmission Planning Outside of the Western Interconnection

The transmission planning interactions in the Western Interconnection are distinct from the interactions in the Eastern Interconnection. In the west, Planning Regions have been organized as a means for the member Transmission Providers and Planning Coordinators to achieve certain transmission planning obligations. However, with the exception of CAISO,[113] the Regions are not NERC Functional Entities, and therefore are not subject to compliance with approved reliability standards (even though they adhere to those standards when performing transmission planning studies) or individually under the jurisdiction of FERC. The individual Transmission Providers are ultimately responsible for compliance with Order 1000 and for demonstrating compliance with all approved reliability standards.

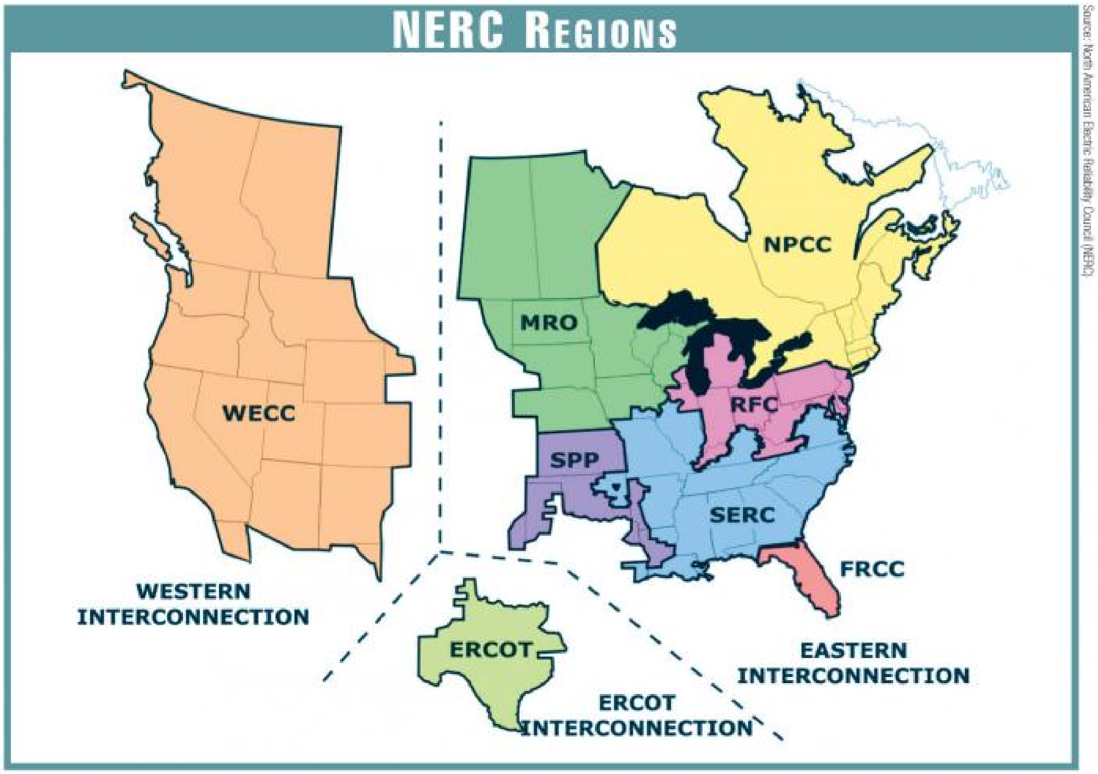
By contrast, in the Eastern Interconnection, regional transmission planning is not only conducted by the ISO/RTOs, but as both the Transmission Provider and Planning Coordinator they are also the entities subject to compliance with FERC Orders and NERC reliability standards.

Six of the eight NERC-delegated Regional Entities are organized within the Eastern Interconnection. Only WECC and ERCOT are organized on an Interconnection-wide basis (see Figure 22). As such, WECC maintains the sole responsibility for promoting reliability and efficient coordination of the Western Interconnection. With regard to transmission, WECC is responsible for developing coordinated planning policies and procedures and ensuring that those procedures are being satisfied, for ensuring compliance with all planning-related reliability standards, and for performing interconnection-wide studies as needed to achieve its mission. There is no single comparable Regional Entity in the other interconnections that performs as broad a scope of planning activities as WECC.

Still, examples of coordinated planning efforts conducted outside the Western Interconnection can serve to inform the efforts in the west on the technical assessment of transmission needs and the coordination of planning efforts.

[113] CAISO is the only Regional Planning entity that is also registered with NERC as a Planning Coordinator, BA, Transmission Operator, and Transmission Service Provider, and is therefore subject to complying with all applicable NERC reliability standards. Further, as a Transmission Provider, CAISO is responsible for filing OATT revisions to comply with the requirements of Order 1000.

**Figure 24: NERC Regional Entities**




***Source***: *NERC*

## 7.1 Southwest Power Pool

The Southwest Power Pool (SPP) is both a Regional Transmission Organization (RTO) mandated by FERC to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity, and a NERC-delegated Regional Entity charged with overseeing compliance enforcement and reliability standards development.[114] The SPP Regional Entity (SPP RE) is an independent and functionally separate division of SPP. Activities performed by the SPP Regional Entity include:[115]

- Regional Reliability Standard Development
- Compliance Monitoring and Enforcement
- Organization Registration and Certification
- Event Analysis and Reliability Assessments
- Training and Education

SPP RE utilizes SPP shared staff to coordinate and facilitate the development of regional reliability standards and to conduct certain technical studies not associated with the compliance monitoring function such as reliability assessments.

[114] http://www.spp.org/
[115] http://www.spp.org/section.asp?pageID=87

As an RTO, SPP is responsible for creating regional transmission expansion plans and is subject to compliance with Order 1000.[116] Through its transmission planning process, which includes participation by its members,[117] regulators, and stakeholders, SPP creates planning models and conducts studies to determine what new transmission is needed to meet the region's long- and near-term needs. SPP does not own or build transmission, but it does conduct a competitive bidding process for all transmission facilities approved for construction or endorsed by the SPP Board through its transmission planning process.

As part of its three-year, Integrated Transmission Planning Process (ITP),[118] SPP conducts near-term, 10-year, and 20-year assessments of transmission needs. The 10- and 20-year assessments are conducted every three years, whereas the near-term assessments are conducted on an annual basis. The first phase of the ITP is the 20-year assessment which focuses on identifying significant (>300kV) transmission projects needed to develop a grid flexible enough to provide benefits to the region across multiple scenarios. The 20-year studies are conducted using a combination of production cost and power flow models to analyze transmission needs under a range of future scenarios.[119] The production cost models are built from publicly available data that is reviewed and updated by SPP members and stakeholders. The power flow model is imported into the production cost model so that consistent transmission topology assumptions are reflected in the models. The transmission topology used as a starting point in the 20-year models reflects projects previously approved in the ITP process as well as projects located at the SPP seam that are known to the SPP staff. Future electricity usage is forecasted by the utilities in the SPP footprint and used as input into the models. Resource expansion plans for each 20-year future studied are developed based on stakeholder input with regard to planned generation and retirements, and the need both to maintain adequate planning reserve margins and to achieve state renewable targets. When the models are complete, system performance is assessed from different perspectives designed to identify transmission expansion projects necessary to accomplish the reliability, policy, and economic objectives of SPP. The perspectives maintained for the 20-year studies ensure the resulting transmission expansion portfolio will:[120]

- Avoid exposure to Category A and B NERC TPL standard criteria violations during the operation of the system under high stresses;[121]

[116] The effective date for SPP's tariff revisions made for Order 1000 regional compliance was March 30, 2014.
[117] SPP has five footprints: Regional Entity, Reserve Sharing Group, Reliability Coordinator Area, RTO, and Energy Imbalance Serve Market. The membership for each footprint varies. A list of SPP members for each footprint can be accessed here: http://www.spp.org/publications/spp_footprints.pdf
[118] http://www.spp.org/section.asp?pageID=129
[119] For its most recent 2013 ITP 20, SPP evaluated transmission needs in the 20-year timeframe across five distinct futures including a business-as-usual scenario and four additional scenarios reflecting different policy assumptions affecting the industry. These four scenarios did not attempt to bookend key drivers affecting the electric system, but rather targeted public policy and technology issues associated with a high degree of uncertainty and expected to have a significant influence on the needs of the transmission system. Specifically, renewable mandates, carbon constraints, and impacts of changes to these policies on system demand were reflected.
[120] SPP, "2013 Integrated Transmission Plan 20-Year Assessment Report", July 30, 2013.
[121] Four seasonal peak hours are focused upon for the 20-year power flow analyses including: summer peak hour, winter peak hour, high wind hour, and low hydro hour.

- Facilitate the use of renewable energy sources as required by policy targets and mandates;
- Contribute to the voltage stability of the system; and
- Reduce congestion and increase opportunities for competition within the SPP Integrated Marketplace where cost justified (benefit-to-cost ratio is at least 1.0).

Since SPP's technical studies are performed on a range of futures, a weighting is applied to each future based on that future's probability of occurrence and magnitude of impact on the needs of the transmission system. The final recommended portfolio of transmission expansions resulting from the 20-year studies are those individual projects providing a reliability, economic, or public policy benefit in the business-as-usual scenario and at least one other scenario.

The second phase of SPP's ITP is the 10-year planning horizon assessment. SPP's 10-year studies (ITP 10) identify both regional and local system upgrades to address the expected reliability, economic, and public policy needs in the 10-year planning horizon. For its 2015 ITP 10, SPP studied two alternative futures: a business as usual future and a future with decreased base load capacity.[122] The business as usual future reflected all enacted public policy, load growth projection of the SPP load serving entities, and SPP member-identified generator additions and retirement. The decreased base load capacity future reflected the retirement of all coal units less than 200 MW, an across-the-board reduction of all hydro capacity by 20%, and utilized the Palmer Drought Severity Index for an average of August 1934 and August 2012 to simulate a reduction in the remaining existing capacity affected by drought conditions. Similar to the ITP 20, a combination of production cost and power flow models are used to analyze transmission needs under the 10-year scenarios. The 10-year models are also developed in a process similar to the 20-year models, with member and stakeholder input collected to develop load, resource, fuel price, and other modeling assumptions. Once the 10-year models are complete, system performance is assessed from different perspectives designed to identify transmission expansion projects necessary to accomplish the reliability, policy, and economic objectives of SPP. The perspectives maintained for the 10-year studies ensure the resulting transmission portfolio will:[123]

- Avoid exposure to Category A (system intact) and B (single contingency) SPP standard criteria violations during the operation of the system under high stresses;[124]
- Facilitate the use of renewable energy sources as required by policy mandates and goals; and
- Reduce congestion and increase opportunities for competition within the SPP Integrated Marketplace where cost-justified (one-year benefit-to-cost ratio is at least 0.9).

Individual projects meeting the performance criteria shown in Figure 23 in both the business as usual future and the alternative future are selected for the final recommended portfolio of transmission expansions in the 10-year planning horizon.

[122] SPP, "2015 STEP", January 5, 2015.
[123] SPP, "2015 Integrated Transmission Plan 10-Year Assessment Report", January 20, 2015.
[124] Two seasonal peak hours are focused upon for the 10-year power flow analyses including: summer peak hour, and off-peak hour with the highest ratio of wind output to load.

Figure 25: Project Performance Criteria for SPP's ITP 10

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

***Source***: *SPP 2015 ITP 10*

SPP's near-term studies focus on immediate (within six years) transmission needed to maintain reliability in accordance with NERC TPL Standards, SPP Criteria, and individual Transmission Owner planning criteria. The models developed for the near-term studies are based on generation dispatch and load information provided to SPP by its Transmission Owners and member BAs. SPP's power flow model development process is conducted using the Model On Demand (MOD). Through this tool, SPP members update their modeling information via web-based applications, making the modeling process more efficient.

SPP is interconnected with two other Planning Regions, the Midcontinent Independent System Operator (MISO) and Southeastern Regional Transmission Planning (SERTP), and has filed separate common tariff language for compliance with the interregional planning requirements of Order 1000. On March 19, 2015 FERC released an order on the compliance filings submitted by SPP and SERTP requiring additional compliance filings to be submitted within 60 days. Outside of the interregional coordination process, SPP has made efforts to refine its coordination efforts by coordinating with its neighbors at every milestone of the planning process and on the same schedule as SPP staff coordinates with SPP stakeholders. Specific coordination activities include providing an opportunity for SPP's neighbors to review and provide edits to the ITP 10 model. For the 2015 planning cycle, SPP received specific feedback on the modeling (load, generation, transmission topology) of its neighbors' respective footprints.

SPP is also a participating Planning Coordinator in the Eastern Interconnection Planning Collaborative (EIPC). EIPC was initiated by a coalition of NERC-registered Planning Coordinators in the Eastern Interconnection and received the same DOE funding as WECC in 2010 to develop long-term interconnection-wide transmission expansion plans. Similar to WECC's approach, the EIPC efforts were intended to build upon, rather than replace, the local and regional transmission planning efforts. From 2010-2011, EIPC's work consisted of creating a combined grid model for the interconnection based on a combination of the members' transmission expansion plans for 2020, performing a reliability analysis of a revised model, and conducting a macroeconomic analysis of eight energy futures in the 20-year planning horizon.[125] The combined grid model was created using the most recent vintage NERC Multi-Regional Modeling Working Group (MMWG) model representing the study year. This model was then revised and updated by the individual member Planning Coordinators to reflect their regional plans. Following a reliability assessment of the model, a subsequent model was created to reflect stakeholder-specified modeling assumptions with regard to future planned generation and transmission facilities. This model allowed the EIPC stakeholders to develop criteria for determining which future projects would be included in the models. This revised model was prepared solely for the purposes of the EIPC study work and was not subjected to a reliability evaluation or introduced into the regional planning processes. It was, however, used as the starting point for all subsequent technical analyses performed for the EIPC study work.

From 2012-2013, EIPC built upon its work conducted during Phase 1 by performing reliability and economic modeling of three future scenarios selected by stakeholders.[126] As a follow-up to the Phase 1 and Phase 2 studies, EIPC conducted additional technical analyses to evaluate the interaction between the natural gas and electric systems, and prepared the Gas-Electric System Interface Study.[127]

## 7.2 Midcontinent Independent System Operator

The Midcontinent Independent System Operator (MISO) is also a Regional Transmission Organization and the NERC Planning Coordinator for its member footprint. As such, MISO performs regional transmission planning in accordance with the requirements set forth by Order 1000[128] and under its obligation to NERC as a Planning Coordinator.

MISO's regional transmission planning process is an integrated and comprehensive planning process, similar to the process performed by CAISO. MISO's overall transmission planning process consists of generator interconnection and transmission service planning elements, but the focus of the process overview presented here will be on MISO's expansion planning activities as part of the MISO Transmission Expansion Plan (MTEP) process.

The MTEP is an annual process involving planning activities that span 18 months. The MTEP seeks to identify proposed transmission projects to ensure the reliability of the MISO system, provide economic benefits, and facilitate public policy directives. The ultimate deliverable of MTEP is a list of transmission projects for recommendation to the MISO Board, and while this is also the case for other ISO/RTO transmission planning processes, the MTEP focuses the planning process around the status and evaluation of transmission projects submitted into the MTEP process.

MTEP Appendix C projects are those projects proposed by Transmission Owners, stakeholders or planning staff for which specific needs have not yet been identified, but are thought to be potentially

[125] http://www.eipconline.com/Phase_I.html
[126] http://www.eipconline.com/Phase_II.html
[127] http://www.eipconline.com/Gas-Electric.html
[128] MISO's tariff revisions for compliance with Order 1000 became effective on June 1, 2013, but MISO is still in the process of addressing FERC's compliance directives with regard to regional planning requirements.

beneficial to the MISO system.[129] All newly proposed projects start as Appendix C projects in the MTEP process, and are not included in the initial power flow models used to perform the baseline reliability assessments.

MTEP Appendix B projects are those demonstrated to be a potential solution to an identified reliability, policy, or economic need. As part of the MTEP process, an initial needs analysis is performed and once a need is identified, potential solutions from the Appendix C projects are tested for effectiveness in meeting the needs or providing benefits. If a project is verified to meet the identified need, it moves into the Appendix B list of projects.

MTEP Appendix A projects are those that have been justified to be the preferred solution to an identified reliability, policy, or economic need. The project justification process includes consideration of a variety of factors including urgency of need and comparison among competing alternatives in terms of operating performance, initial investment costs, robustness of the solution, longevity of the solution provided, and performance against other economic metrics. Pending Appendix A projects are recommended for approval by the MISO Board.

To identify transmission needs and evaluate alternatives, MISO conducts technical studies in both a 5- and 10-year planning horizon for reliability studies, and a 5-, 10-, and 15-year planning horizon for economic studies. Reliability studies are performed using the PSS/E power flow tool, and the economic studies are performed using PROMOD. The base models used to perform both the economic[130] and reliability studies are created using the MOD with information populated by the MISO Transmission Owners and Load Serving Entities. The models are reviewed by MISO stakeholders and further supplemented with vendor-provided[131] or additional stakeholder-derived modeling data and assumptions as needed. In particular, MISO looks to the State Commissions participating in the MTEP process to provide inputs related to projections of load growth, resource requirements, transmission siting authority and environmental concerns to assist MISO in the development of realistic transmission expansion projects and alternatives to meet the needs identified.[132] MISO has outlined in detail the opportunities and requirements for the exchange of information used to inform the MTEP process including the timeline for submitting modeling data and assumptions.[133]

In addition to the base models, MISO considers alternative Futures that are used to support the MISO Value-Based Planning Process (MVP). The objective of the MVP process is to develop the most robust

[129] MISO, "Transmission Planning Business Practice Manual," November 30, 2014.

[130] MISO creates a power flow case for use in the economic model as a starting point. Additional model post-processing is then required to prepare the model for study using the production cost tool.

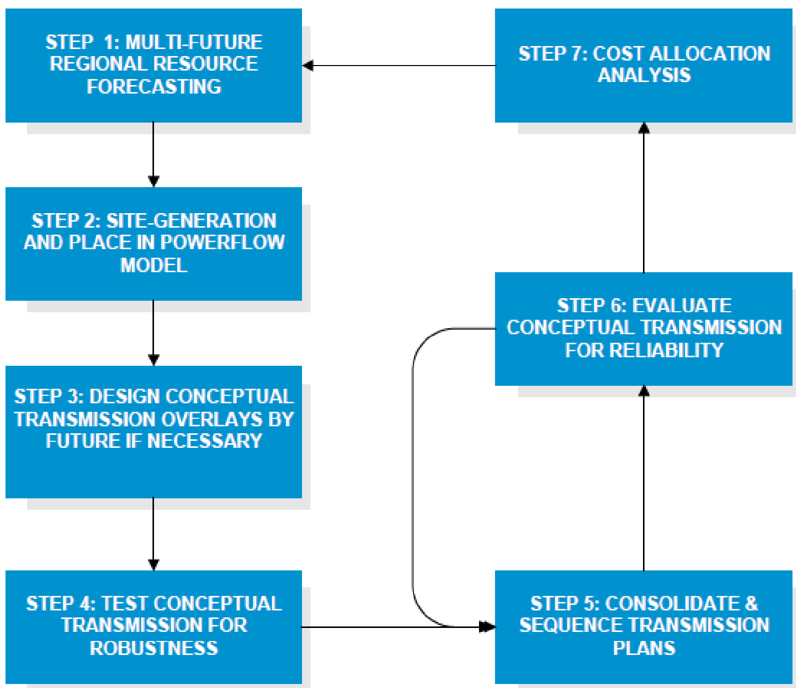
[131] MISO uses a vendor database as the source of load, generation, emissions, and fuel price assumptions primarily for locations outside of the MISO footprint.

[132] The Organization of MISO States (OMS) is an active stakeholder in the MTEP process. The OMS is a non-profit self-governing organization with representatives from each state in the MISO footprint and states with regulatory jurisdiction over entities participating in MISO. The OMS coordinates regulatory oversight among the states and makes coordinated recommendations to MISO and the MISO Board of Directors.

[133] MTEP Information Exchange Schedules & Requirements: https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP%20Information%20Exchange%20Schedules%20and%20Requirements.pdf

(highest value, most flexible, and lowest risk) portfolio of transmission expansions under a wide variety of economic and policy conditions. The Futures evaluated by MISO reflect a reasonable range of uncertainty surrounding key modeling inputs such as fuel costs, environmental regulations, available technology, and resource locations. Developing the Futures and evaluating system needs under those Futures requires the use of multiple study techniques. For example, in addition to production cost and power flow models, MISO uses the Electric Generation Expansion Analysis System (EGEAS) to develop the generation expansion portfolios reflected in the alternative Futures. The EGEAS identifies the least-cost generation portfolios needed to meet resource adequacy and public policy requirements of the MISO system for each future scenario. The MISO's MVP consists of seven steps as illustrated in Figure 26.

**Figure 26: MISO Value-Based Planning Process**




***Source**: MISO*

MISO facilitates sub-regional planning meetings for the purpose of providing an interface to stakeholders on a more localized basis than the centralized stakeholder meetings of the MTEP process. These meetings are open stakeholder meetings, and are held three times during the MTEP planning cycle to provide initial input into the MTEP process, review and provide input into the MTEP planning models, review system performance issues identified during the baseline and alternative future technical assessments, and to comment on the proposed preferred solutions.

To address cross-border studies, MISO has an existing Joint Operating Agreement with PJM Interconnection and has filed separate interregional coordination agreements with both SPP and SERTP to meet the interregional compliance requirements of Order 1000. MISO recently concluded a Joint

Planning Study with PJM with the goal of identifying projects that would address congestion at the MISO/PJM seam. This was the first instance in which MISO and PJM engaged in a coordinated study effort that sought to identify an interregional project or projects that could be approved in the respective regional plans. Although many lessons were learned from the effort, a business case for the approval of an interregional project was not established. As a result of this effort, the MISO and PJM stakeholders have identified concerns related to the planning process, metrics applied to evaluation of projects, and cost allocation. In response, MISO and PJM have initiated an effort to work with stakeholders to identify ways to improve interregional planning going forward.

To support the MISO and SPP interregional coordination process, the organizations recently formed the Joint Planning Committee to begin working on a Coordinated System Plan. The Committee will conduct a study including reliability, economic, public policy and market evaluations of the joint systems, and will look to apply lessons learned from the MISO/PJM joint planning efforts. MISO forms joint planning committees with all of its neighboring transmission providers, consisting of stakeholders and the planning staff of MISO and other neighboring planning regions. These forums are used to discuss planning issues and concerns and to facilitate the exchange of planning data and assumptions.

MISO also participates in interconnection-wide planning activities as a participating Planning Coordinator in the Eastern Interconnection Planning Collaborative (EIPC), similar to SPP.

### 7.2.1 Midwest Reliability Organization

The Midwest Reliability Organization (MRO) is one of the six NERC-designated Regional Entities in the Eastern Interconnection, and is responsible for auditing MISO for compliance with NERC reliability standards as a BA, Interchange Authority, Planning Coordinator, Reliability Coordinator, and Transmission Service Provider. In addition to its compliance monitoring and enforcement functions, MRO provides seasonal and long-term assessments of the MRO region’s ability to meet the demand for electricity and analyzes and reports on regional system events.[134]

The MRO Region covers roughly one million square miles spanning the provinces of Saskatchewan and Manitoba, and all or parts of the states of Illinois, Iowa, Minnesota, Michigan, Montana, Nebraska, North Dakota, South Dakota and Wisconsin.

As part of its system assessment function, on an annual basis MRO collects, reviews, and endorses the seasonal and long-term reliability assessments of the Planning Coordinator areas within the MRO Region. In addition to MISO, the Mid-Continent Area Power Pool (MAPP), Manitoba Hydro, SaskPower, and SPP are Planning Coordinators within the MRO Region.

Notably, MISO is also under the jurisdiction of two other Regional Entities including the Southeastern Electric Reliability Council (SERC) and Reliability*First* Corporation (RFC). As such, MISO provides input into the system assessments performed by these Regional Entities for the portions of its system that fall into their Regional Entity footprint.

[134] MRO Homepage: https://www.midwestreliability.org/Pages/default.aspx

As a Regional Entity, MRO currently collects modeling data from Transmission Owners, Transmission Providers, Generator Owners, and Resource Planners to compile an annual set of power flow models for its regional footprint.[135] Upon approval, these models are provided to the MMWG, which compiles the regional footprint cases from all the Eastern Reliability Entities to create interconnection-wide cases. These cases are used as the starting point for the power flow models used by both SPP and MISO.

## 7.3 Link to Key Documents

SPP Integrated Transmission Planning

MISO Transmission Expansion Planning

Eastern Interconnection Planning Collaborative

[135] Per the new MOD-032-1 NERC Reliability Standard, the process for compiling modeling data to create interconnection-wide power flow cases will be changing. MRO is in the process of working with the Planning Coordinator areas within its region to develop the most effective model building procedure to comply with the new standard.

# Concluding Observations

On March 24, 2015 NTTG became the second western Planning Region after CAISO to fully comply with the regional planning requirements of Order 1000, and all four Planning Regions are well underway with their Order 1000 regional planning processes. The interconnection will be watching these processes unfold, and will undoubtedly be waiting for the first project to receive a regional cost allocation.

With the regional transmission planning processes underway, focus is turning to the development of the interregional coordination procedures and the scope of WECC-Region coordination efforts. Central to these discussions will be the regional planning process milestones and timelines, processes for deriving planning data and assumptions, and technical study methodologies. Differences in the regional planning cycle durations (biennial versus annual) could lead to a misalignment in planning horizons and may contribute to inconsistencies in planning data and assumptions across regions (e.g. varying vintages of planning data used to inform the regional plans). Together with differences in technical study methodologies, establishing a single interregional coordination procedure for the joint evaluation of ITPs across the regions will be challenging.

The consistency of planning assumptions across regions could be improved through direct requests for input and data at established points during the regional planning processes, and if they are accompanied by commitments to provide that input. MISO’s Information Exchange Schedules & Requirements outlined for the MTEP process is a good example of a clear, documented timeline for the exchange of planning data and the identification of those entities responsible for providing input into the process. To increase transparency, such documentation should include a description of the alternate data source if the requested data is not received.

Further, the consistency of planning assumptions across Regions could be maintained by a centralized, continuously updated repository of planning data. This would ensure access to a common set of current assumptions for any variety of transmission planning activities, including interconnection-wide studies. WECC has coordinated the assimilation of planning data and assumptions across the interconnection for many years as part of the PCC Annual Study Program and TEPPC efforts. These efforts have been extremely valuable to regional and interconnection-wide planning efforts. However, the independent timelines of various planning activities necessitates the need for ad hoc updating of WECC planning data, contributing to inconsistencies between planning efforts. The BCCS has the ability to address this issue by allowing Planning Coordinators to submit updated data to WECC at the same time they provide updated information for use in the regional planning process. When the time comes to build a base case the same data used for one process will be available to inform the other process. TEPPC’s migration to a continual update process for its 10 and 20-year databases will maintain a current set of economic planning assumptions as long as the Regions provide updates to TEPPC and TEPPC incorporates those updates into its databases. To ensure this process is not overly burdensome, an information exchange schedule as previously described could be developed and coordinated based on major planning process milestones.

To mitigate differences regarding the planning horizon or study methodology between regions, greater flexibility and agility within the regional planning processes is needed. The "round-trip" approach taken by NTTG with regard to its technical studies provides such agility. It would enable a Region to export an additional hour(s) for reliability studies if it was determined the initial hour(s) selected for evaluation by a Region should be supplemented for the joint evaluation of an ITP. Within the regional planning processes, the "round-trip" approach would expand the options for hours of interest that could be evaluated without being constrained by the suite of WECC base cases developed for a given PCC Annual Study Program. This constraint also has the potential to be mitigated by the BCCS, but the timeline for its full implementation is uncertain. Further, the "round-trip" approach would provide consistency between the reliability and economic studies used to identify transmission system needs within the regional planning studies.

Order 1000 has placed increased emphasis on regional and interregional planning efforts. However, the hierarchy of local, regional, and interconnection-wide coordinated planning efforts collectively ensures the continued reliable and efficient operation of the bulk electric system. Efficient and effective coordination of these efforts is key to ensuring transmission planning efforts are meaningful and non-duplicative.

At the same time, stakeholders play a key role in ensuring transmission planning efforts are transparent and produce a robust portfolio of transmission expansions that have a high likelihood of being needed and well-utilized under the most likely, but uncertain energy futures. All four western Planning Regions and WECC provide for the input and participation of a broad range of stakeholders in the transmission planning process. The extent to which this opportunity is exercised, however, varies across the interconnection. For example, while the WestConnect regional planning process allows for voting membership of state agencies and key interest groups on the Planning Management Committee, no entities have yet elected to participate as members in the process. At the other end of the spectrum is the CAISO transmission planning process, in which state agencies work together with the CAISO to identify scenarios and ensure a broad range of policy considerations are incorporated in the technical studies. The result of this coordination and collaboration is a robust and comprehensive transmission planning process, which is the goal of all of the regional planning efforts.